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Clean Coal for the 21st Century: What Will It Take?

The Sixth Clean Coal Technology Conference focused on the ability of clean coal technologies (CCTs) to meet increasingly demanding environmental requirements while simultaneously remaining competitive in both international and domestic markets. Conference speakers assessed environmental, economic, and technical issues and identified approaches that will help enable CCTs to be deployed in an era of competing, interrelated demands for energy, economic growth, and environmental protection. Recognition was given to the dynamic changes that will result from increasing competition in electricity and fuel markets and industry restructuring, both domestically and internationally.

Energy use, critical to economic growth, is growing quickly in many regions of the world. Much of this increased demand can be met by coal with technologies that achieve environmental goals while keeping the cost per unit of energy competitive. Private sector experience and results from the CCT Demonstration Program are providing information on economic, environmental, and market issues that will enable conclusions to be drawn about the competitiveness of the CCTs domestically and internationally.

The industry/government partnership, cemented over the past 11 years, is focused on moving the technologies into the domestic and international marketplace. The Sixth Clean Coal Technology Conference provided a forum to discuss benchmark issues and the role and need for these technologies in the next millennium.

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LARGE-SCALE CFB COMBUSTION DEMONSTRATION PROJECT

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ABSTRACT

The Jacksonville Electric Authority's large-scale CFB demonstration project is described. Given the early stage of project development, the paper focuses on the project organizational structure, its role within the Department of Energy's Clean Coal Technology Demonstration Program, and the projected environmental performance. A description of the CFB combustion process is included.

I. INTRODUCTION

The U.S. Department of Energy (DOE) and the Jacksonville Electric Authority (JEA) have entered into an agreement that will advance DOE's Clean Coal Technology Demonstration (CCT) Program and provide JEA's customers with an economical, environmentally clean source of electricity in the 21st century.

DOE and JEA will share the $309 million cost for refurbishment of one unit of an existing power plant with a new boiler that employs the atmospheric-pressure, circulating fluidized bed (CFB) technology owned by Foster Wheeler (FW). FW will fabricate and install the new unit. The project will restore the originally-designed electricity generating capacity of JEA's Northside Generation Station's Unit 2, which has been out of service since 1983. At the same time, the new technology will reduce the Northside Station's local air emissions and ground water consumption. At 300 MW, this will be the largest CFB boiler built to date.

The CFB technology is a technique for burning coal and other fuels or mixtures of fuels in the presence of granulated limestone, at significantly lower temperatures than traditional boiler technology. These features lead to dramatically lower sulfur dioxide (SO_2) emissions due to reaction of the generated SO_2 with the limestone, and lower oxides of nitrogen (NO_x) production because of the lower furnace temperatures. The CFB technology has been demonstrated at smaller sizes to reduce overall pollutant-forming impurities by more than 90 percent. Although CFBs are capable of achieving the 98 percent SO_2 removal that JEA requires, a flue-gas scrubber will be installed after the CFB to improve the process economics.

JEA is the largest public power company in Florida and the eighth largest in the United States. It currently serves over 326,000 customers, and is experiencing an energy growth rate of more than 3 percent per year, hence the need to repower Northside's Unit 2. The project is expected to increase Northside's annual electrical output by more than 2 ½ times.

For DOE, successful completion of this project will complete a piece of the CCT program that has been in the works for some years. The CFB concept was originally proposed and adopted during Round I of the CCT program. Its intended site was the Arvah Hopkins Power Station in Tallahassee, Florida. Ultimately, the City of Tallahassee decided not to go forward. The project then was moved to York County, Pennsylvania, where it ultimately met the same fate. In the present circumstances, the project has found its ideal home: an existing power station in need of a boiler featuring high efficiency and superior environmental performance.

CFB technology has been successful in smaller, industrial-sized applications, but only recently has been considered for larger utility-scale power plants. DOE helped to test a 110 MW CFB combustor at a power station in Colorado in an early CCT project. The JEA unit will produce nearly 300 MWe (gross) and about 265 MWe (net) — a good deal more than double the size of the Colorado unit.

DOE's cost contribution to the JEA Northside Power Station project will total $74.7 million, which is the originally approved total less costs incurred during the Tallahassee and York iterations of the project. This will constitute about 24 percent of the total cost of the Unit 2 retrofit. JEA will provide the balance of the $309 million. The DOE demonstration project will repower Northside's Unit 2. After it is on line, JEA's present plans include retrofitting the Northside Unit 1, which is identical to the mothballed Unit 2, with FW's CFB technology. Only Unit 2 will be funded by DOE. Northside has a third unit: a 564 MWe natural gas and heavy oil-fired unit, which will continue to operate in its current configuration.

Preliminary engineering for Unit 2 has already begun and construction is expected to begin in March 1999. DOE's cost-sharing will also include two years of demonstration test runs, which are expected to take place from April, 2002 through March, 2004. During the test runs, both straight coal and blends of coal and petroleum coke will be burned.

II. INTEGRATED RESOURCE PLANNING (IRP)

Following the recommendation of the Energy Policy Act of 1992, JEA adopted the IRP process as its standard practice for determining the need for facilities. This technique takes into consideration the full range of alternatives available, including new capacity, technology upgrades, power purchase, efficiency improvements, energy conservation, cogeneration, and renewable energy resources. Based upon this approach, JEA's board adopted a reference plan in 1995. This plan is reviewed and updated annually.

The 1996 annual update confirmed the existence for JEA of a 3 percent per year growth in electricity demand. Based upon that finding, it became apparent that new generating capacity would be required on-line by the year 2002, even considering all other options available.

It was further decided at that time that, in line with the uncertainties prevalent in the fuels markets, the new unit should be capable of utilizing cheap, abundant fuel. Coal heads this list, with petroleum ("pet") coke running a close second. JEA has been burning blends of coal and pet coke since January 1997 at its St. John River Power Park, which is located adjacent to the Northside Power Station.

After considering its suite of generating assets and all of its options, a cornerstone of the JEA's 1996 IRP study was the decision to repower Northside Units 1 and 2.

III. COMMUNITY COMMITTMENT

As an organization, JEA recognizes its responsibility to the community, and is committed to making Jacksonville "the premier city in the southeast in which to live and do business." In pursuit of this vision, JEA established the stringent environmental requirements and goals for this project — goals that exceed current limits required by law. The project will result in at least a 10 percent decrease in the emissions of SO_2, NO_x, and particulates, as well as at least a 10 percent decrease in the consumption of ground water by the Northside Generating Station relative to the established baseline years of 1994 and 1995. This will be accomplished while increasing the nameplate generating capacity of the facility by over 35 percent, and the annual output over current operations by more than 2 ½ times, as the station is now running at well below its capacity.

The permitting process and preliminary design for Northside Unit 2 have begun. A number of permits relating to air quality, water use and quality, solid waste handling and storage, etc., will ultimately be obtained on the path to making this project an accomplished reality. Prior to commencing the formal permitting process, JEA has been consulting with residents of the Northside and other areas of Jacksonville, environmental interests, the Jacksonville area business community, and other interested stakeholders to ensure that all views are considered, and that everyone is heard. JEA's plan is based upon the results of these consultations.

IV. PROJECT ORGANIZATIONAL STRUCTURE

JEA and FW are mutually working toward an agreement that will tie FW, which owns the CFB technology and is to manage the engineering, procurement and construction, to the long-term success of the project. With FW participating in ongoing profits (or losses) from the Northside Unit 2 project (and Unit 1 as well), it is expected that the best balance will be reached between the goals of capital cost minimization and operating performance maximization. This arrangement is also expected to reduce project implementation costs through reducing the bulk of overall project management.

JEA expects to take the entire electrical output from Northside Unit 2 over the facility's entire life. However, JEA will only be obligated contractually to take the output for a defined period of time and that only if the facility performs to certain defined standards. This arrangement provides incentive for FW to provide a facility that will remain competitive long after its one-year warranty period is over.

The partnering agreement currently in negotiation between JEA and FW will take advantage of the services and expertise of all three of FW's major operating groups: Foster Wheeler Power Systems will have an equity position in the unit and will be JEA's partner in operating the facility; Foster Wheeler Energy Corporation will supply the new CFB boilers; and Foster Wheeler USA Corporation (FWUSA) will provide engineering and construction management services. Foster Wheeler Environmental Corporation, a subsidiary of FWUSA will provide environmental permitting services. The intent of the partnering agreement is to specify how the parties will jointly own and operate the facility, arrange financing, and undertake project development, permitting, engineering, procurement, and construction of the plant. Some portions of the project will be implemented by JEA staff, supplemented by Black & Veatch (B&V) through a pre-existing alliance with JEA, for engineering services. An integrated project organization consisting of JEA, FW, and B&V is currently being developed

V. THE CLEAN COAL TECHNOLOGY PROGRAM

Under Public Law (PL) 99-190, the U.S. Congress authorized and funded DOE to support the construction and operation of demonstration facilities selected for cost-shared financial assistance as part of DOE's CCT Program. In December 1985, funds were made available for the first round of CCT and a Program Opportunity Notice (PON) was issued by DOE. In response, proposals were received and projects were selected by DOE for negotiation. Alternate projects were also selected. The forerunner of the present JEA CFB project was ultimately selected from the alternate list for implementation. The overall CCT Program objective for the JEA project is to demonstrate the feasibility of the CFB technology at a large-scale utility size.

The overall CCT program is today, after some thirteen years, winding down. After five separate PONs, responses to them, and a number of completed projects, the application of large-scale CFB technology to the repowering of JEA's Northside Power Station Unit 2 will be one of the last projects undertaken under the CCT program. In a sense, this particular project spans the entire life of the CCT program.

The original intent of the CCT program was to encourage the use of abundant U.S. coal resources in the midst of rapidly tightening environmental restrictions on their use. Much U.S. coal is high in sulfur and other pollutant precursors, and means needed to be found to extract the coal's energy without generating the pollutants. While many schemes had been advanced to do this, none of them had been able to reach the commercial scale because of the risk involved and the economic consequences of failure. As an incentive to private companies to sponsor these large projects, Congress, through DOE, provided monetary and financing incentives to encourage such projects.

VI. PROJECT SCOPE

The overall project involves construction and operation of two CFB combustors to be fueled by coal and pet coke to repower two existing steam turbines, each generating nearly 300 MWe. The project will be located at JEA's Northside Generating Station, which currently consists of three heavy oil and natural gas fired steam units and four diesel oil fired combustion turbine units. Units 1 and 3 are currently in operation and generate steam from units that came on line in November, 1966 and June 1977, respectively. Unit 2 was completed in March 1972 but has not operated since 1983 due to early boiler failure. Unit 2's boiler has, moreover, been removed and the site cleared to the concrete pad. The balance of the Unit 2 equipment remains in place, preserved.

In addition to the new CFB combustor itself and the air pollution control systems, new equipment for the project will include a stack, and solid fuel, e.g., coal, pet coke, limestone, and ash handling facilities. The project will also require overhaul and/or modifications of existing systems such as steam turbines, condensate and feedwater systems, circulating water systems, water treatment systems, plant electrical distribution systems, the switchyard, and plant control systems.

New construction and activities associated with the CFB combustor will occupy about 60 acres of previously disturbed land at the Northside site. Options under consideration for transport of fuel include (1) an extension of conveyors from the nearby St. John River

Power Park, and (2) construction of new receiving, handling, and storage facilities for coal. Limestone and ash storage and handling facilities also will be required. Wherever possible, existing facilities and infrastructure will be used for the project.

Project activities will include engineering and design, permitting, equipment procurement, construction, startup, and a 24-month demonstration of the commercial feasibility of the technology. Construction is scheduled to begin in March 1999 and finish in late 2001. Startup will occur in early 2002, and demonstration of the technology will begin in April of that year. During the two-year demonstration, Unit 2 will be operated on several different types of coal and coal/fuel blends, to explore the flexibility of the CFB technology. Upon completion of the demonstration program, the facility will continue in commercial operation.

VII. CFB TECHNOLOGY DESCRIPTION

The CFB process offers the means for efficient burning of a wide variety of fuels while maintaining low emissions. Fuel is fed to the lower furnace where it is burned in an upward flow of combustion air. Fuel ash and unburned fuel thus carried out of the furnace are collected by a cyclone separator and returned to the lower furnace. Granulated limestone, used as a sulfur sorbent, is also fed to the lower furnace. Furnace temperatures are maintained in the relatively cool range of 1500 – 1700 F by heat absorbing surfaces. This process offers the following advantages:

- Fuel flexibility — The relatively low furnace temperatures are below the ash softening range for nearly all fuels. As a result, the furnace design is independent of ash characteristics, which allows a given furnace to handle a wide range of fuels.
- Low SO_2 Emissions — Limestone is an effective sulfur sorbent in the temperature range of 1500 – 1700 F. SO_2 removal efficiencies of 95 percent and higher with good sorbent utilization have been demonstrated.
- Low NO_x Emissions — Low furnace temperature plus staging of combustion air generate little NO_x .
- High Combustion Efficiency — The long solids residence time resulting from the collection/recirculation of solids via the cyclone, plus the vigorous solids/gas contact in the furnace caused by the fluidization airflow, result in high combustion efficiency, even with difficult-to-burn fuels.

300 MWe CFB Boiler Design Features

The 300 MWe CFB design described herein is for reference and is based on a typical eastern bituminous coal, although it could be designed for any fuel. The following are the steam conditions and fuel analysis on which the design will be based:

Fuel Analysis (Weight Percent)	Coal			Coke		
	Min.	Max.	Design	Min.	Max.	Design
Carbon	49.3	86.0	65.20	78.0	89.0	83.0
Hydrogen	3.2	6.0	4.58	3.2	5.8	3.7
Oxygen	3.0	9.8	8.02	0.1	1.8	0.5
Nitrogen	0.4	1.9	1.30	0.4	2.0	1.7
Sulfur	0.5	4.5	0.71	3.0	8.0	4.5
Ash	7.0	15.0	8.15	na	3.0	0.4
H_2O	na	15.0	12.00	na	15.0	6.2
Volatiles	20.0	40.0	33.00	7.0	na	9.0
HHV, Btu/lb	10,000	na	11,600	13,000	na	14,360

Steam Conditions @ MCR	Superheat	Reheat
Flow Rate, pph	2,011,185	1,747,079
Pressure, psia	2535	596
Temperature, F	1000	1000

The boiler contains a single, water-cooled furnace. An integrated recycle heat exchanger (INTREX™), which contains intermediate and finishing superheater surfaces, is located along the lower rear wall of the furnace. Three steam-cooled cyclones are provided. The backpass is a parallel-pass design and contains the primary superheater, reheater, economizer, and air heater surfaces.

The process design is the same as for other, smaller FW CFB boilers. Fuel and sorbent feed size, furnace velocity, furnace temperature and bed pressure drop are unchanged. Performance characteristics such as fuel burnout, sorbent utilization, boiler efficiency and emissions will be as good as, or better than, smaller units. Key design features include:

- Single furnace with division walls.
- Steam-cooled cyclones.
- INTREX™
- Parallel-pass reheat control.
- Startup duct burners.
- Water-cooled air plenum and fluidizing nozzles.
- Fluidized ash cooler.
- Fuel feed.

Furnace

The main influences on CFB boiler configuration are the specified steam conditions and the fuel type. Compared with industrial boilers, the superheat and reheat duty of utility boilers is a greater percentage of the total input because of the higher steam pressure and temperature. Higher feed water temperature in the utility boiler further increases the furnace heat duty due to the larger air heater duty, which is transferred to the furnace.

Fuel quality affects auxiliary equipment sizing more than the furnace sizing for most fuels. The coal and ash flows increase by two to five times when waste coal is substituted for bituminous coal. However, the air and gas flows increase by only about 7 and 12 percent, respectively, because the higher heating values (HHV) of waste coal and lignite are only about 30 percent that of bituminous coal. The range of fuel conditions normally determine auxiliary equipment selection while the furnace design and performance are optimized for the design fuel conditions. Experience has shown FW that the CFB boiler can handle various fuels in each boiler with ease.

Furnace temperatures can be effectively controlled by changing the solids loading in the upper furnace by varying the primary/secondary air ratio, and by changing the solids flow over the INTREX™ superheater surface.

The evaporative duty of the CFB unit is provided by the enclosure and division walls of the furnace and INTREX™. This arrangement of furnace and INTREX™ surface gives uniform heat removal, thereby minimizing temperature variations. The furnace division walls, which have been used in several FW CFB boilers will also provide more uniform solids loading into the three cyclones.

Steam-Cooled Cyclone

The function of the cyclone in the CFB furnace is to capture sufficient solids to ensure good bed quality, which is manifested by proper furnace temperatures and low pressure drop in the furnace, low carbon loss, and low emissions. The efficiency of this key piece of equipment is of paramount importance to the success of the CFB.

The 300 MWe unit uses three steam-cooled cyclones, each of which is lined with FW's standard one-inch thick low-cement refractory on studs as protection against erosion. Higher stud densities are used in areas of high solids impact, and operating experience has shown that this refractory system works reliably in this service.

The scale-up of cyclones is usually accompanied by a corresponding fear of reduced collection efficiency. Classical cyclone theory, which does not account for particle interactions, predicts that separation efficiency decreases as the diameter of the cyclone increases. In the case of CFB cyclones, it appears that, with the heavy solids loading, interaction between particles does take place, and to a significant extent. It appears that the larger particles carry smaller particles with them to the wall of the cyclone, and thus out the bottom. FW's has conducted extensive testing that indicates that larger cyclones in this service do have high efficiencies.

INTREX™ Heat Exchanger

In large CFB boilers, about a fourth of the total superheat duty occurs within the solids circulating loop, either through surfaces such as wing-walls, or via a heat exchanger. In larger boilers, FW utilizes the INTREX™ exchanger.

Hot recirculating solids enter the inlet channels of the INTREX™ via J-valves. Normally the solids are passed into the superheater cells by fluidizing both the inlet channels and the superheater cells. During start-up, only the inlet cells are fluidized. By varying the mode of fluidization in the inlet channels and cells, solids flow can be controlled so as to control INTREX™ superheat pickup and, thus, furnace temperature.

The INTREX™ enclosure is constructed of MONO-WALL™ water-wall tubing and comprises several inlet channels, superheat bundle cells, and a common return channel to distribute solids evenly back into the furnace. Being an integral part of the furnace, the INTREX™ eliminates the need for hot-loop expansion joints.

The INTREX™ design for the 300 MW unit will be based upon one used at the NISCO plant. Five years of operating experience on these two 100 MWe units has shown that the design works well:

- Furnace temperature control — As discussed, changes to the fluidization mode can effectively adjust the furnace temperature.
- Reduced corrosion and erosion — The high-temperature superheat surface in the INTREX™ is not exposed to corrosive elements in the flue gas stream. This means that corrosive fuels are not a threat to the INTREX™. Also, the very low fluidization velocity, i.e., < 1.0 ft/s, and the very fine particle sizes, i.e., ~200μ eliminate the potential for internal erosion damage.
- Low maintenance — The INTREX™ design eliminates expansion joints and mechanical valves used in other designs. This makes the INTREX™ nearly maintenance-free.
- Independent superheat/reheat control — With all of the reheat duty in the backpass and most of the superheating done in the INTREX™, superheat and reheat temperatures can be controlled somewhat independently over a wide range of conditions.

Parallel Pass Reheat Control

The backpass contains two parallel gas passes; the front pass houses the reheat surface and the rear pass the primary superheater. Gas flow is biased between the two passes by dampers located underneath each pass. Reheat temperature control is accomplished without water spray attemperation by controlling the gas flowing past the reheater. This design has been utilized successfully by FW in non-CFB boilers to 930 MWe.

Start-Up Duct Burners

For start-up, duct burners firing natural gas (backed-up by oil) will be used to preheat the primary air stream which in turn uniformly preheats the bed material to the temperature needed for solid fuel combustion. This method is 40 percent more efficient than the use of start-up burners located on the furnace wall.

Water-Cooled Air Plenum

A plenum under the grid at the base of the furnace distributes primary air to the fluidizing nozzles in the furnace floor. FW uses a water-cooled plenum, formed from tubing which then forms the furnace walls. The plenum is designed to handle high temperature gas so that boiler start-up time is minimized.

Bottom Ash Cooler

A bottom ash cooler is required to cool the ash to a temperature that is acceptable to the ash handling system. The 300 MWe CFB boiler uses the FW patented stripper/cooler design, which is used normally for large CFB boilers or for high ash fuel in smaller boilers. The stripping (classifying)/cooling process consists of draining material from the bed and fluidizing this material in the stripper zone at a velocity sufficient to strip the required amount of fines from the stream, then returning these fines to the furnace. The remaining material, which is primarily coarse, will pass through the next cooling zones to the ash drain in the floor of the last zone. These zones are fluidized and cooled by air from the air heater and from the primary fan. Economizer tube bundles may be contained in the cooling zones to help cool the solids down to typically 500^0F. The stripper section is important for returning the fines, typically unburned carbon and unutilized limestone, to the furnace thereby increasing carbon burnout efficiency and reducing specific limestone consumption. The stripper/cooler raises the boiler efficiency significantly by recovering heat from the bottom ash.

Fluidizing Nozzles

Directional and non-directional fluidizing nozzles are available. These proven nozzle designs provide for low pressure drop, and minimize the potential for back-sifting and pluggage.

Fuel Feed System

The fuel feed system consists of a number of individual trains, each of which is made up of a bunker outlet gate valve, a belt feeder, an isolation gate valve and an air-swept fuel distributor.

The system is designed to accommodate a positive pressure condition with the furnace pressure balance point set at the cyclone inlets. Seal air is provided from the primary air fan to the belt feeder. This fan also provides air to the air swept fuel distributors. The air swept fuel distributor adds horizontal momentum to the fuel to assist in injecting it into the boiler. Seal legs of material are provided in the downspouts above the belt feeders. These legs are of sufficient height to seal against the maximum furnace pressures anticipated.

The proven air-swept fuel distributors have been carefully designed to propel the fuel into the furnace in such a manner as to avoid hang-ups and back-flow from the furnace and to distribute the fuel throughout the bed. They are the result of a research program involving numerous flow models and operating experience. Air is admitted into each distributor at two locations in a carefully designed manner to maintain the proper velocity and flow pattern.

Emissions Performance

SO_2 emissions are controlled with limestone feed; 90 percent SO_2 removal is typical and 95 to 98 percent removal is achieved in some units. The Ca/S ratio for 90 percent SO_2 capture is normally around 2.0 for fuels with moderate to high sulfur content. SO_2 reduction is enhanced by good mixing in the bed and by increased excess O_2 level. Limestone ash in the bed helps to improve the bed quality, especially for low ash fuels, because most limestone ash is less friable than the fuel ash and thus stays in the bed longer.

NO_X emissions are inherently low due to low furnace temperatures and staged combustion. Most of the NO_X is formed in the lower portion of the furnace, with NO_X emissions increasing with fuel volatile content, furnace temperature, O_2 level, and free lime available in the furnace and decreasing with an increase in the amount of char available. Therefore, minimizing excess O_2 in the furnace is important for NO_x control. But this is in conflict with SO_2 reduction. The FW CFB process is optimized in such a way that the dense bed in the lower furnace provides a long residence time for char and limestone particles, thereby minimizing both SO_2 and NO_x emissions.

VIII. PROJECTED OPERATIONAL RESULTS

Northside Unit 2 has not operated since 1983 and Units 1 and 3 have been operating on heavy oil and/or natural gas at annual capacity factors of less than 40 percent of their combined nameplate capacities. At the completion of this project, Northside Station will consist of Units 1 and 2, both equipped with nominal 300 MW CFB furnaces and Unit 3 as currently configured.

In line with its corporate policy of fostering both the business environment and the general quality of life in the Jacksonville area, JEA has set a goal for the total Northside Station, operating at full capacity, to exhibit at least a 10 percent reduction from its present performance in the annual stack emissions of each of three critical pollutants: SO_2, NO_x, and particulates.

JEA and FW anticipate that SO_2 emissions from Units 1 and 2 will be limited to 0.17 pounds per million Btu (lb/mmBtu), NO_x to 0.11 lb/mmBtu, and total particulate emissions to 0.017 lb/mmBtu (PM_{10} to 0.013 lb/mmBtu). Emissions from Unit 3 will be limited as necessary for Northside Station to achieve its overall goals which may mean operation of Unit 3 with the fuel blends and within the annual capacity factors that have characterized its operation in recent years.

JEA is also committed to at least a 10 percent reduction in groundwater consumption from recent levels. This will be accomplished by increased recycling of the treated wastewater produced at the station. Currently, plant wastewater is treated with lime, clarified in settling basins, and discharged to percolation ponds. With this project, the discharge of the treated water to the ponds will be significantly reduced.

IX. CFB DEMONSTRATION PROGRAM

Successful operation of the new CFB unit will be demonstrated through a series of operability, reliability, and performance tests during the first two years of operation as follows:

Operability Testing — These tests will determine the operability of the CFB boiler and its ancillaries under various conditions, including startup, shutdown, changing load and full load

Reliability Determination Tests — This will entail the collection of reliability data during the demonstration period to determine the overall reliability of the boiler and associated equipment. The data will be analyzed to determine the monthly and overall availability and capacity factor, plus it will identify the duration and causes of forced outages and forced load reductions.

Performance Tests — Achievement of guaranteed performance will be verified through testing in accordance with applicable codes and EPA/State emission test methods. Specific testing will address boiler efficiency, power consumption, and environmental performance.

Fuel Flexibility Tests — In addition to the above operational testing, fuel flexibility tests will be conducted on individual coals and coal/fuel blends to evaluate boiler operability, capacity, and performance. Such tests will be used to establish fuel, process parameters, and boiler performance factors for use in determining the extent to which fuel characteristics can be varied.

Conclusions would also be developed with respect to fuel, related operating and maintenance practices, costs, environmental compliance, and other factors. Total production-related costs using the various fuels will be evaluated for use in future CFB installations.

Other significant aspects of the testing plan will be long-term durability testing of the CFB system and off-line inspections to evaluate wear and fouling characteristics of the equipment.

X. CONCLUSION

The performance and characteristics of the atmospheric-pressure, CFB are well-proven, although at sizes somewhat smaller than the 300 MW unit proposed to replace the furnace for the Northside Generating Station's Unit 2. In fact, this project will represent about a 100 percent scale-up of the technology.

Having said that, the principles involved are well known, and none of the individual pieces of the CFB unit proposed are in question. Given its considerable experience with this technology and the equity position that FW will take in the project, there appears to be little reason to doubt that the CFB proposed will perform as well or better than anticipated.

From JEA's and its customers' points-of-view, FW's CFB promises to provide environmental enhancement and needed power. From FW's point-of-view, the efficacy of their flagship process is proven at a much larger scale, and becomes, therefore, more widely applicable. From the DOE point-of-view, a lingering CCT Round I project will be successfully closed-out. This defines the ideal: A win-win-win situation.

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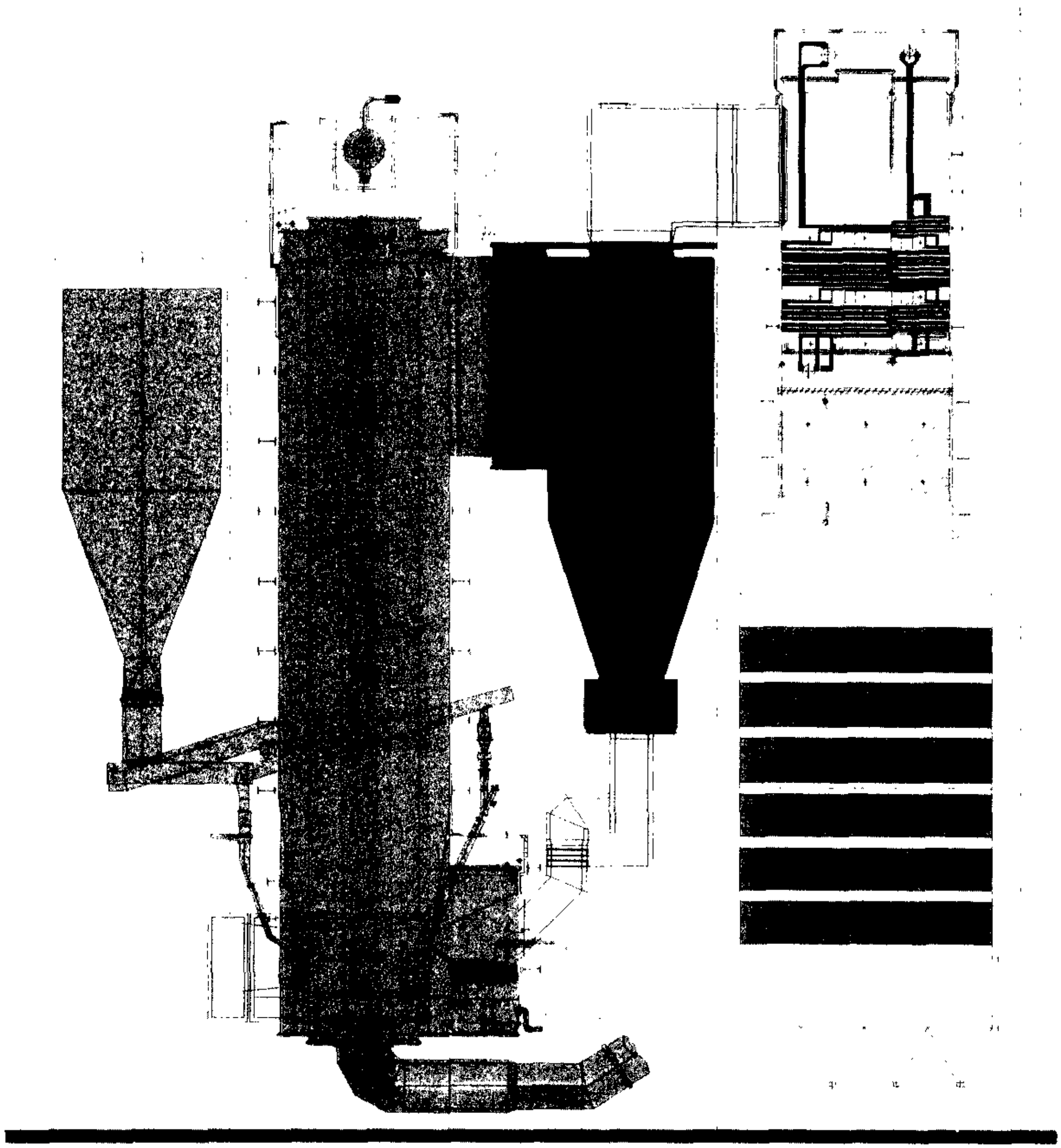
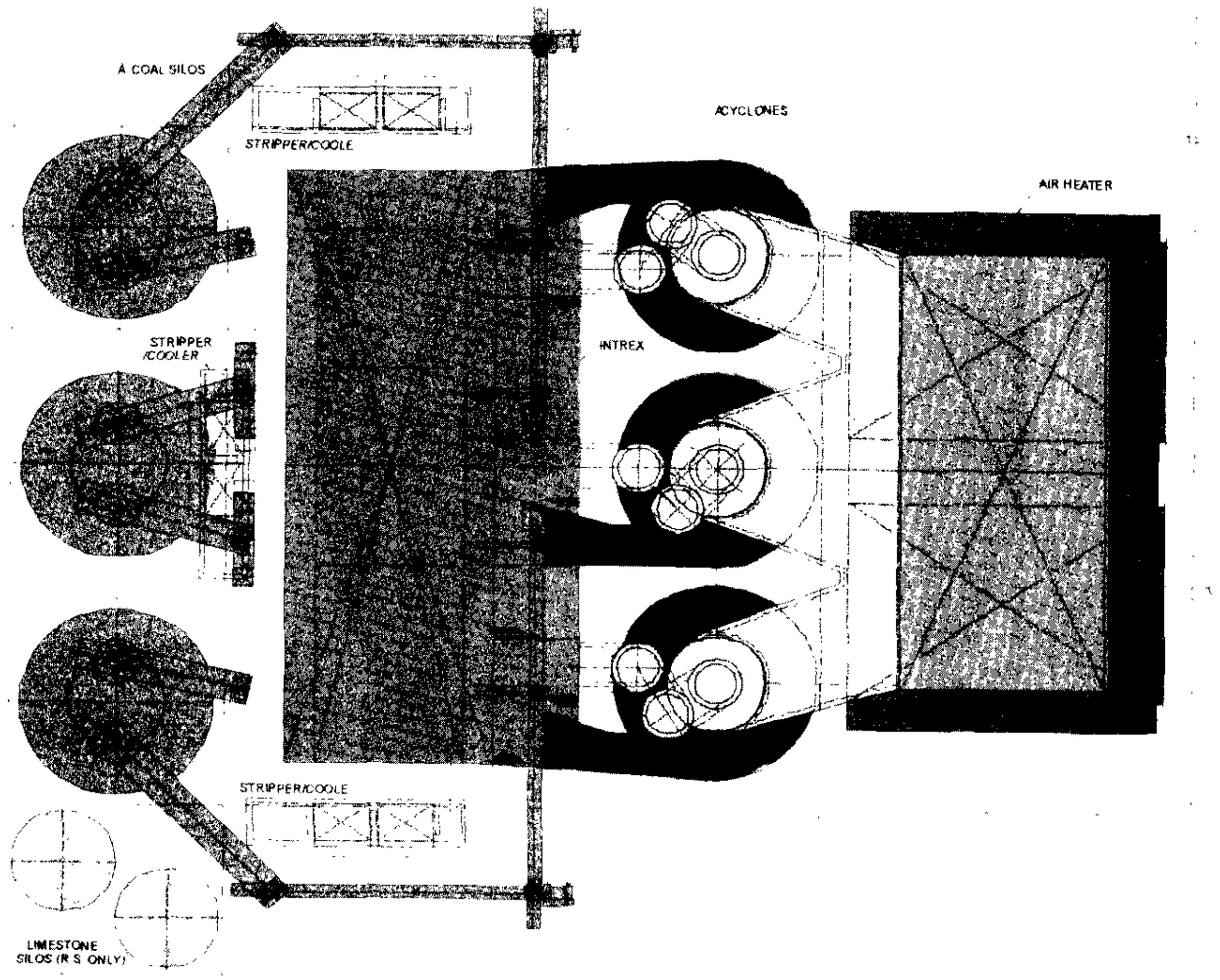
Foster Wheeler
300 MWe CFB



Side Elevation

Foster Wheeler
300 MWe CFB



Plan View

THE LAKELAND MCINTOSH UNIT 4 DEMONSTRATION PROJECT UTILIZING FOSTER WHEELER'S PRESSURIZED CIRCULATING FLUIDIZED-BED COMBUSTION TECHNOLOGY

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ABSTRACT

On December 8, 1997, the City of Lakeland, Florida, signed a Cooperative Agreement with the U.S. Department of Energy (DOE) that will facilitate the demonstration of the Pressurized Circulating Fluidized-Bed Combustion (PCFB) technology being developed by Foster Wheeler. The project will be conducted under the DOE Clean Coal Technology Program at the City of Lakeland's McIntosh Power Station in Lakeland, Polk County, Florida.

The Lakeland McIntosh Unit 4 Project is a nominal 190 MWe combined cycle power plant designed to burn a range of low- to high-sulfur coals. The plant will employ a Westinghouse 401 gas turbine engine in conjunction with a 2400psig/1000°F/1000°F steam turbine, and it will demonstrate both the "PCFB" and "topped PCFB" combustion technologies.

This paper describes the Foster Wheeler PCFB and Topped PCFB technologies, discusses the Lakeland McIntosh Unit 4 Project, and presents the results of a candle filter test performed with Lakeland coal and limestone.

I. INTRODUCTION

The City of Lakeland operates two power stations totaling approximately 820 MWe of generating capacity of which about 80% is wholly owned by the Lakeland Department of Electric & Water Utilities. The McIntosh Station on the North side of Lake Parker is the larger of the two with approximately 590 MWe of generating capacity; the smaller Larsen Station on the South side of the lake has about 230 MWe of generating capacity.

The City of Lakeland has experienced and is forecasting steady load growth within its system of approximately 15 MWe per year, which will result in a capacity shortfall of approximately 60 MWe by the year 2000. In addition, Lakeland expects to retire 70 MWe of inefficient generating capacity. Faced with this load growth and anticipated retirement of older units, Lakeland plans to add approximately 200-250 MWe of new generating capacity.

To help meet their new power generation requirement, Lakeland plans to build a nominal 190 MWe plant utilizing both Foster Wheeler's Pressurized Circulating Fluidized-Bed (PCFB) Combustion and Topped PCFB technologies. The McIntosh Unit 4 PCFB plant will be constructed on undeveloped land located adjacent to the existing McIntosh Unit 3. The PCFB plant will be designed to burn a range of coals including both the current Eastern Kentucky coal burned in the conventional pulverized coal fired Unit 3 as well as lower priced, high ash, high sulfur coals that are available on the open market. Limestone will be procured from Florida sources while the ash will be disposed in landfill or marketed.

The plant will be funded in part through the U.S. Department of Energy (DOE) Clean Coal Technology (CCT) Program. The DOE funding results from a combination of two previous Clean Coal awards: The DMEC-1 PCFB Repowering Project selected under Round III and the Four Rivers Energy Modernization Project (FREMP) selected under Round V. The DMEC-1 project was intended to demonstrate non-topping PCFB technology (gas turbine temperature is essentially the same as the PCFB temperature), while the FREMP project was planned to demonstrate Topped PCFB technology (gas turbine inlet temperature is markedly higher than the PCFB temperature).

II. PROJECT COST AND SCHEDULE

The total cost and funding summaries for McIntosh Unit 4 PCFB Demonstration Project in "as spent" dollars are shown below. The total project costs include the total cost to construct the facility, certain project related offsite costs, 4 years of operation and maintenance (O&M) costs, owner's costs and permitting costs.

		($1000)
COSTS	Total Project Cost	387,970
	Lakeland In-Kinds	2,030
	TOTAL COST	**390,000**
FUNDS	Lakeland In-Kind	2,030
	Lakeland	192,970
	DOE	195,000
	TOTAL FUND	**390,000**

The total McIntosh Unit 4 PCFB Demonstration project costs have been divided between the two Cooperative Agreements.

The project schedule is shown in Figure 1. The permitting and licensing processes required by the State of Florida and by the National Environmental Policy Act are expected to take about 15 months. The design of the facility (Phase 1) will coincide with and continue until the permitting process is completed. Thereafter, Phase 2 will begin with the general release for fabrication and construction, and last for 32 months to mechanical completion. Phase 3 will begin with the start up of the first (non-topping PCFB) demonstration. After 12 months of operation and testing, the carbonizer leg of the plant will be tied into the plant and the second (topping PCFB) demonstration begun. Topping PCFB operation and testing will continue for three years, after which the plant will be released to Lakeland for commercial operation.

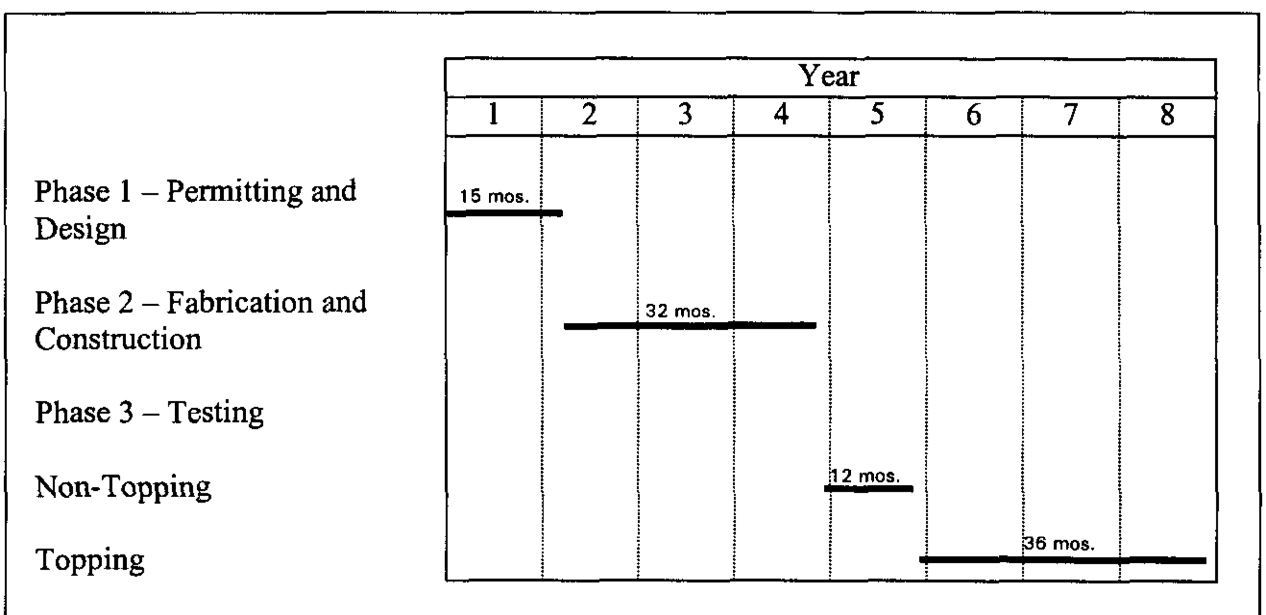

Figure 1 Lakeland Demonstration Plant Project Schedule

The McIntosh Unit will be constructed as two sequential demonstrations that will demonstrate both non-topping PCFB and topping PCFB technology, thereby satisfying the objectives of both the DMEC and FREMP projects. Each of the two systems has its own benefits, and so Foster Wheeler anticipates that both will have application in the future.

The non-topping PCFB will be best suited for power stations in the size range of 100-400 MWe and is especially well suited for repowering. Benefits of the non-topping PCFB include:

1. Low Capital Cost – Studies performed in cooperation with EPRI and others have shown that coal fired central power stations utilizing non-topping PCB technology have the potential to cost under $1000/KW.

2. Low Emission – The non-topping PCFB can achieve very low emissions of all pollutants including sulfur dioxide, nitrogen oxides, particulates, carbon monoxide, and other pollutants. The solid waste generated by the system is inert. Tests performed in Foster Wheeler's facilities show the potential of the technology to achieve emissions as low as or lower than conventional or other advanced technologies including coal gasification.

3. Benefits of Repowering – The non-topping PCFB will add about 20-25% to the output from a steam plant through the addition of a gas turbine. This is accomplished with a corresponding improvement in net plant heat rate of about 10%, low emissions, and low capital cost, and with a very small plant footprint. This fits well with the objectives of repowering existing power stations.

The topping PCFB technology is developed to take advantage of the efficiency increases provided by higher gas turbine firing temperatures. The topping PCFB can achieve very high cycle efficiencies, approaching 50%, and its economics benefit substantially from economies of scale. Thus, the topping PCFB technology is targeted for new large central station power plants in the size of 250 to 500 MWe. Benefits of the topping cycle include those listed above and very high plant efficiencies achieved by utilizing high temperature gas turbine technologies of the future.

III. PROCESS DESCRIPTION

A PCFB plant is a combined cycle power generation system employing gas and steam turbines and combusting solid fossil fuel in a pressurized circulating fluidized bed. Tubes contained in the PCFB generate, superheat, and reheat steam for use with the most advanced steam turbines (Rankine cycle) and the hot, pressurized combustion exhaust gas emanating from the PCFB in turn can drive a gas turbine (Brayton cycle) for additional power generation. A non-topped PCFB plant can achieve thermal efficiencies in excess of 40 percent (HHV) and have a levelized busbar cost of electricity below any competing coal technology. In addition to the economic benefits, the built-in feature of environmental control (SO_2 and NO_X) in the combustion process eliminates the need for any external gas clean up such as scrubbers. A PCFB can also burn a much wider range of coals than a pulverized-coal-fired boiler. PCFB combined-cycle power plants offer real economic incentives for low cost electric power generation in an environmentally acceptable manner, while burning a wide range of low cost, abundant coals.

Figure 2 represents a simplified schematic of Foster Wheeler's PCFB Combustion (non-topped) cycle. Combustion and fluidizing air is supplied from the compressor section of the gas turbine to the PCFB combustor located inside a pressure vessel. Coal and sorbent (usually limestone) are mixed with water into a paste which is pumped into the combustion chamber using reciprocating pumps commonly used in the concrete industry. The same type of pumps have been successfully proven in a number of pressurized fluidized bed combustion plants and facilities around the world. The limestone sorbent captures sulfur in situ as sulfur dioxide, and nitrogen oxides are controlled by temperature and pressure.

Combustion takes place in the fluidized bed combustor at a temperature of approximately 1550 - 1600°F and typically 10 to 16 atmosphere, depending on the gas turbine used. Particulate matter is removed from the flue gas exiting the combustor using cyclones and ceramic barrier filters, such as a Westinghouse ceramic candle type Hot Gas Particulate Filter System (HGPFS), located between the PCFB and gas turbine. The high temperature, high pressure HGPFS is similar to that tested for 6000 hours at the American Electric Power PFBC Demonstration facility (Tidd) in Brilliant, Ohio [1]. Modules of this type of filter system have also undergone extensive testing at Foster Wheeler's PFB pilot plants in Livingston, New Jersey, and in Karhula, Finland [2] [3], and in the Wilsonville Power Systems Development Facility operated by Southern Company Services for the DOE [4]. In addition to protecting the gas turbine from erosion, the HGPFS eliminates the need for any particulate removal at the stack thereby eliminating the need for a back-end electrostatic precipitator (ESP) or baghouse.

The hot gas cleaned by the filter system expands through the gas turbine, exhausts to a heat recovery unit, and vents to a stack. The heat recovered from both the combustor and the heat recovery unit is used to raise, superheat and reheat steam for use in the steam turbine. Approximately 15 to 25% of the total power produced is generated in the gas turbine, and the balance is generated in the steam turbine.

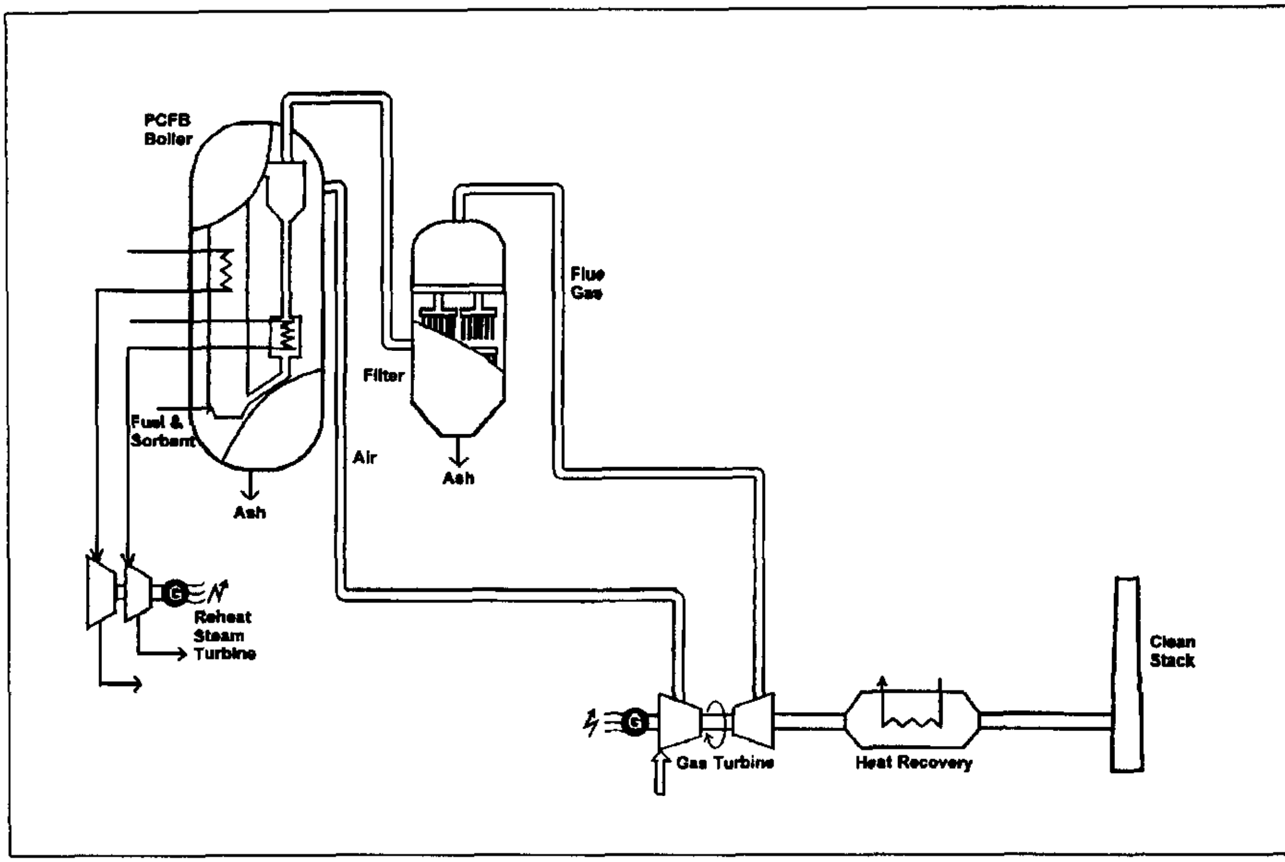

Figure 2 Foster Wheeler Non-Topped PCFB Cycle

Figure 3 shows a simplified schematic of Foster Wheeler's Topped PCFB Combustion cycle. The topped PCFB technology integrates a carbonizer island and gas turbine topping combustor in the PCFB cycle. The additional components allow the firing temperature of the gas turbine to be increased to state-of-the-art levels via the combustion of a coal derived, low-Btu syngas produced in the carbonizer and fired in the gas turbine topping combustor. This has the effect of increasing the gas turbine power output relative to the steam turbine, thereby increasing the plant efficiency to levels approaching 50 percent.

The carbonizer is an air-blown jetting, fluidized bed operating at 1600°F to 1800°F. Dried coal and sorbent are fed to the carbonizer using a conventional pneumatic transport system employing lock hoppers. The coal is devolatilized and partially gasified to produce a low-Btu syngas and a solid residue (called char) that is removed from the carbonizer and transferred to the PCFB for combustion. The limestone sorbent captures sulfur as calcium sulfide and also acts as a stabilizer to prevent bed agglomeration and to aid in partial gasification. The particulate matter in the syngas (char plus reacted and unreacted sorbent) is removed using a cyclone and Westinghouse HGPFS similar to that used for the PCFB. This collected material, together with the main char flow from the carbonizer, are transferred to the PCFB to complete combustion and sulfur removal. The hot, clean syngas is fired in the topping combustor to raise the turbine inlet temperature to the firing temperature of the gas turbine.

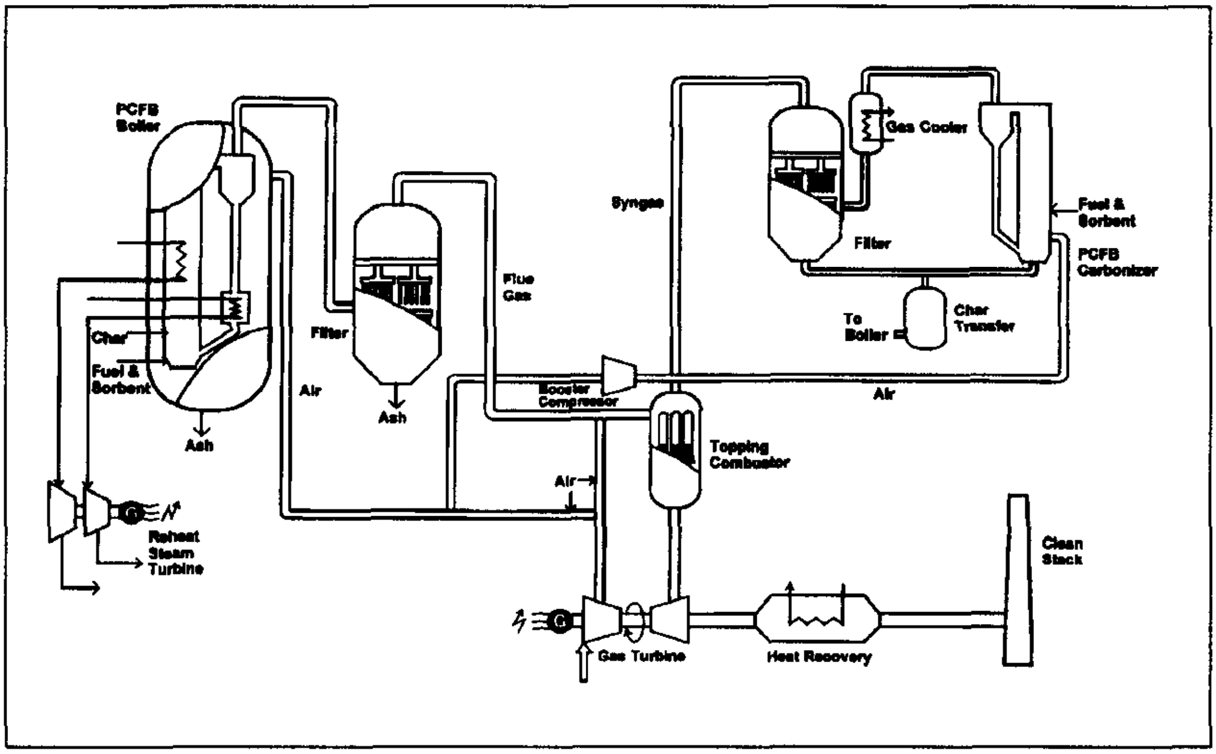

Figure 3 Foster Wheeler Topped PCFB Cycle

IV. DESIGN BASIS

The McIntosh Project was originally planned to be a 170 MWe unit utilizing a Westinghouse 251B12 gas turbine with a 1975°F firing temperature. Recent advances in gas turbine technology have raised rotor inlet temperatures to 2400°F and higher for increased power output and efficiency. Because of Lakeland's need for additional power and increased efficiency, we now plan on replacing the 251 with the 401 machine being developed by Westinghouse. In our plant, the 401 will have a firing temperature greater than 2400°F and generate 87 MWe of power. Substitution of the 401 in lieu of the 251 increases both the power output and the efficiency of the demonstration plant. Table 1 summarizes design data for the now 189 MWe 42.8 percent efficient* plant:

Table 1 McIntosh Unit 4 PCFB Predicted Plant Performance Estimates

	McIntosh Unit 4
Gas Turbine Power Output, MW	87.4
Steam Turbine Power Output, MW	118.3
Net Power Output, MW	189.1
Net Plant Heat Rate, Btu/KW-h	7972*
Net Plant Efficiency, %	42.8*
SO_2 Removal, %	95
NO_X Emission, lb/MMBtu	0.17
Particulate Emission, lb/MMBtu	0.02

*Coal higher heating value basis.

The air output from the 401 is greater than that required by the carbonizer and PCFB. Rather than put this excess in the PCFB, thereby increasing the PCFB excess air and NO_X emission, we have elected to bypass the excess around the PCFB and inject it into the PCFB exhaust gas downstream of the PCFB cyclone. This bypass arrangement offers additional advantages of a smaller PCFB and a reduced (1300°F) filter inlet temperature. The latter (1300°F versus 1550°F) simplifies filter element material selections, extends candle life, and substantially reduces the potential for ash bridging or alkali vapor problems in the filter and gas turbine respectively. The fuel gas valving required by the 401 topping combustor has a 1400°F limit. To assure successful operation, the carbonizer syngas will be cooled to 1200°F via a heat exchanger placed between the cyclone and candle filter. As a result, the advantages of reduced (1200°F versus 1760°F) gas temperature will also apply to the carbonizer leg of the plant.

V. HOT GAS FILTER TESTS

Recognizing the importance of the candle filter system, Foster Wheeler has conducted a nominal 1000 hour filter test with support from Westinghouse at its PCFB pilot plant in Karhula, Finland. The objectives of the tests, which used Lakeland coal and limestone, were to:

- demonstrate that the ash generated by the Lakeland coal and limestone could be easily removed from the PCFB exhaust gas without creating reentrainment or bridging problems in the Westinghouse filter system;
- investigate the performance of new candle materials being developed by different manufacturers;
- investigate candle filter material and ash behavior at two different temperature levels, i.e., 1550°F and 1400°F.

Table 2 shows the design conditions of Foster Wheeler's 10 MWt Karhula PCFB Pilot Plant and Figure 4 is a schematic of the facility. The Karhula unit is an integrated

PCFB facility, which incorporates the same mechanical design features that will be utilized in commercial plants. Key components of the test facility include complete fuel handling and paste feed systems, pneumatic sorbent and sand injection systems, a pressurized furnace with radiant omega tube heat transfer surfaces, hot cyclone, hot gas filter, and ash cooling and depressurization systems. The facility also facilitates testing of materials and coatings for gas turbine blades. At the 10 MWt scale, the Karhula facility operates at the same conditions as a commercial process plant. The conditions include combustor operating pressure and temperature, fluidizing velocity, arrangement of heat transfer surfaces, heat transfer rates, solids distribution and emissions control.

Table 2 Karhula PCFB Pilot Plant Design Data

Description	Condition
Heat Input (nominal)	34 MMBtu/h (10 MWt)
Fuel Feed Rate (max.), lb/h	6350
Gas Flow Rate (max.), lb/h	43,650
Operating Temperature, ^{o}F	1,300 – 1,700
Operating Pressure, psia	up to 230

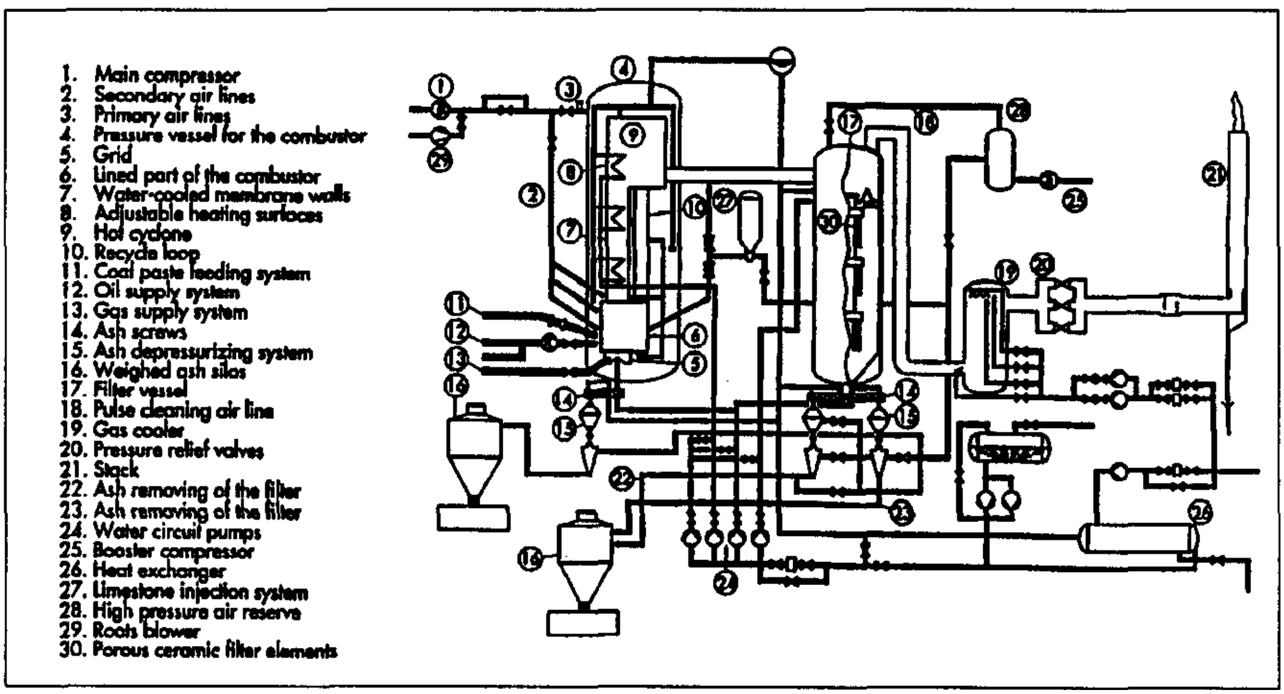

Figure 4 Schematic of Foster Wheeler Karhula PCFB Pilot Plant

The PCFB combustion cell and cyclone are located within a 12-ft. diameter by 46-ft. tall pressure vessel. Compared with the combustion cell and cyclone, the pressure vessel has been purposely oversized to facilitate ease of operation and component change-outs in a laboratory environment. The lower part of the combustion cell consists of an air distribution grid and refractory lined walls through which fuel, limestone, and secondary air enter at various elevations. Above this region, water cooled membrane walls extend up to the top of the cell. Double omega panels are located at several elevations in this section to help cool the combustion gases before they exit to a cyclone at the top of the cell.

Air is fed to the top of the pressure vessel, and it flows down and around the combustion cell to the bottom where it enters the combustion chamber through the grid. Secondary air is fed in separately through multiple injection points located at several elevations. Coal is injected at the bottom of the cell as a coal-water paste via a piston type pump. Sorbent, for control of SO_2 emissions, can be injected separately by pneumatic means or it can be fed with the coal-water paste. The heat released by the burning coal is absorbed by the membrane walls, omega panels, and a continuously circulating mixture of fly ash and limestone. The latter are carried to the top of the unit by the combustion exhaust gas and removed by the cyclone. The separated solids drain from the cyclone into a fluidized bed cooling section and after cooling are returned to the bottom of the unit for recirculation and heat absorption. The cyclone particle laden exhaust gas exits the pressure vessel via a refractory lined pipe and proceeds to a Westinghouse ceramic candle filter. The filter cluster contains 128 candles and is described in Table 3. The particulate in the gas from the PCFB cyclone collects on the outer surface of the candles as the gas flows through the porous ceramic walls of the candle elements. The clean gas flows up inside the candles and passes through Westinghouse proprietary fail-safe devices. The fail-safe device is very important. It significantly reduces the candle gas flow if a candle should break. This prevents significant particle penetration and protects the gas turbine from erosion while still yielding acceptable stack gas particulate emissions. After passing through the fail-safe, the gas flow from each candle is then collected in a manifold and exits from a collection pipe on the clean side of the filter at the top of the filter vessel. After exiting the filter, the gas is cooled by a water spray, depressured via valving, and vented to a stack. The collected ash is removed from the surface of the candles by periodic back pulses of high pressure air. The ash cake blown off the candle falls by gravity, assisted by the general downward flow of gas, to the bottom of the vessel, drains to a screw cooler, and is depressured in a lock hopper for disposal.

Table 3 Specification of the Westinghouse Candle Filter at Karhula

Parameter	
Number of filter plenums	3
Number of candles in each plenum	38 top/38 middle/52 bottom
Total Candles/Cluster	128
Number of Clusters	1
Filtration area of candles, ft^2	384
Maximum design pressure, psia	232
Maximum design temperature, ^oF	1,652
Maximum pulse pressure, psi	580
Length of filter cluster, ft	17.7
Diameter of filter cluster, ft	3.3
Vessel diameter, ft	8
Vessel height, ft	39
Vessel thickness, in.	0.8

The Karhula filter system typically operates with silicon carbide-based candle elements manufactured by Schumacher and Pall. For this test run, however, a portion of these candles were removed and replaced with candles of six different materials being developed by various manufacturers; this would be the first time most of these new/ advanced materials were to be exposed to an actual PCFB operating environment.

The 1000 hour test was conducted in two segments, each of which spanned about six weeks. Each segment contained about 500 hours of operation with a shutdown for inspection near the midpoint. The first segment was completed in April 1997 and the second in November 1997. Lakeland coal and sorbent were used throughout the entire test and Table 4 presents the filter operating data. In Segment 1 the filter operated at about 1550°F and in Segment 2 air was bypassed around the PCFB and injected into the cyclone exhaust gas to yield a 1400°F filter.

Table 4 PCFB Filter Operating Data

Parameter	Unit	Segment I	Segment II
Pressure at filter inlet (max)	psia	164	161
Temperature at filter inlet (max)	^oF	1550	1400
Duration (on coal)	hrs	454	581

VI. CERAMIC FILTER PERFORMANCE

Dust emission measurements conducted during the first 275 hours of operation revealed no signs of dust leaks. Inspection at the first shutdown revealed no candle failures, no ash bridging issue, and no indication of any other problem, and testing resumed. During the second half of the Segment 1 testing, three of the alumina mullite type candle elements failed. These elements were part of a batch that had been operated in the Tidd Plant PFB filter program, accumulating over 1100 operating hours. It is suspected that these elements may have suffered prior structural damage during disassembly and handling from the Tidd facility and subsequent shipping to Karhula, Finland. All candle elements from this batch were subsequently removed from Karhula service.

For Segment 2 testing, the candle count was reduced to 90 elements to maintain the same Segment 1 filter face velocity at the reduced gas temperature. Six new types of oxide based elements were included in the Segment 2 testing, totaling 30 candles. Early in the Segment 2 testing, a total of nine candles from two of the new type materials experienced unacceptable early degradation and were removed. They were replaced with old silicon carbide and old alumina/mullite candles. The degradation experienced with the new candle materials were basically manufacturing issues, thus indicating that further development will be needed to achieve commercial readiness. The Westinghouse fail-safe devices functioned as designed, effectively preventing any significant ash leaks to the filter clean gas outlet. Testing proceeded through Segment 2 without futher issue and testing objectives were achieved:

- We operated the hot gas filter unit for over 1000 hours using the Lakeland specification coal/sorbent with no evidence of ash bridging issues. This was demonstrated at both 1550F and 1400F conditions. The filter unit was effectively cleaned by reverse pulse jet means and operated with a stable and acceptable baseline pressure drop.

- We successfully introduced and pre-qualified four of six new oxide based ceramic filter materials, achieving over 500 hours of operation. These materials show promise for even higher operating temperatures (consistent with Non-Topped PCFB operation) and lower cost. In addition, testing of our old commercially available alumina/mullite and silicon carbide candle elements continued through the 1000 hour program. These elements have cumulative operating hours that range from 2200 to 3000 hours.

In March 1998, a carbonizer test run will be conducted in Foster Wheeler's PFB pilot plant located in Livingston, New Jersey. The test will be conducted with the Lakeland coal and limestone to confirm the suitability of proposed plant operating conditions as well as confirm gas yields, heating values, sulfur capture efficiencies, filter performance, etc.

Later this year a Foster Wheeler designed carbonizer-PCFB-gas turbine module with a Westinghouse candle filter system and a 7 MWe equivalent power output will be started up at the Southern Company Services Power Systems Development Facility in Wilsonville, Alabama. This will be the first time a topping combustor and gas turbine are operated with/integrated with a carbonizer and PCFB. The operation of this facility will be a major milestone in the McIntosh demonstration plant effort, and we look forward to its successful completion.

VII. CONCLUSION

The City of Lakeland has signed a Cooperative Agreement with the DOE to build and demonstrate a PCFB plant designed for a 189 MWe power output. The project, known as McIntosh Unit 4 PCFB Demonstration Project, is scheduled to begin operation in 2002. The plant will demonstrate both the PCFB and Topped PCFB technologies being developed by Foster Wheeler. After a four-year demonstration period, the City of Lakeland plans to operate the plant commercially to provide low-cost power to its distribution system.

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PIÑON PINE PROJECT GASIFIER START-UP

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PAPER UNAVAILABLE AT TIME OF PRINTING

For copies of the paper contact the presenter.

TECO
TAMPA ELECTRIC

Tampa Electric Company
Polk Power Station IGCC Project
Project Status

Presented at:
Sixth Annual Clean Coal Technology Conference
Reno, Nevada
May, 1998

John E. McDaniel (Speaker)
Engineering Fellow
And
Charles A. Shelnut
General Manager
Polk Power Station
Tampa Electric Company

Over the last eight years, Tampa Electric Company has taken the Polk Power Station from a concept to a reality. In 1996, we reported on the permitting, engineering, construction, contracting, and staffing of the project. Our January, 1997, paper at the Fifth Annual Clean Coal Technology Conference in Tampa discussed checkout and startup experiences and the early operating history of the plant. In this year's paper, we would like to focus on the plant's reliability growth and the results of the alternate fuel tests we have conducted to date. In order to view our operations results in the proper perspective, it will be helpful to first briefly discuss some background of the Polk Power Station Project.

I. BACKGROUND

PARTICIPANTS

Tampa Electric Company (TEC) is an investor-owned electric utility, headquartered in Tampa, Florida. It is the principal, wholly-owned subsidiary of TECO Energy, Inc., an energy related holding company heavily involved in coal mining, transportation, and utilization. TEC has about 3650 MW of generating capacity. Over 97 percent of TEC's power is produced from coal. TEC serves over 500,000 customers in an area of about 2,000 square miles in west-central Florida, primarily in and around Tampa, Florida.

TECO Power Services (TPS) is a subsidiary of TECO Energy, Inc., and an affiliate of TEC. This company was formed in the late 1980's to take advantage of the opportunities in the non-regulated utility generation market. TPS currently owns and operates a 295 MW natural gas-fired combined cycle power plant in Hardee County, Florida. Seminole Electric Cooperative and TEC are purchasing the output of this plant under a twenty-year power sales agreement. In addition, TPS owns and operates a 78 MW plant in Guatemala.

TPS is responsible for the overall project management for the DOE portion of this IGCC project. TPS is also concentrating on commercialization of this IGCC technology as part of the Cooperative Agreement with the U.S. Department of Energy.

The project is partially funded by the U.S. Department of Energy (DOE) under Round III of its Clean Coal Technology Program. The research was sponsored by the U.S. Department of Energy's Federal Energy Technology Center, under contract DE-FC-21-91MC27363 with Tampa Electric Company, PO Box 111, Tampa, Fl 33601: Fax: 941-428-5927

OBJECTIVES

Polk Power Station is an integral part of TEC's generation expansion plan. TEC's original objective was to build a coal-based generating unit providing reliable, low-cost electric power. IGCC technology will meet those requirements.

Demonstration of the oxygen-blown entrained-flow IGCC technology is expected to show that such a plant can achieve significant reductions of SO_2 and NO_x emissions when compared to existing and future conventional coal-fired power plants. In addition, this project is expected to demonstrate the technical feasibility of commercial scale IGCC technology. Only commercially available equipment has been used for this project. The approach supported by DOE is the highly integrated arrangement of these commercially available pieces of hardware and systems in a new arrangement which is intended to optimize cycle performance, costs, and marketability at a commercially acceptable size of nominally 250 MW (net).

SITE SELECTION

The plant site is a 4300-acre tract about 11 miles west of Fort Meade and 11 miles south of Mulberry in Polk County, Florida. The process through which this site was selected is one of the many success stories of the project.

In late 1989, TEC formed an independent citizen's task force made up of 17 people representing environmental and community leaders, educators, and economists to help guide the site search. Some of the various groups who had members on the task force were: The National Audubon Society, Florida Audubon Society, 1000 Friends of Florida, Sierra Club, The Hillsborough Environmental Coalition, University of South Florida, and others. TEC made sure that at least half of the group was comprised of members of the environmental community. TEC knew that protecting the environment would be a very high priority in selecting the plant's technology and site.

The task force conducted a year-long study of more than 35 sites in six counties with the assistance of a professional environmental consulting firm.

The task force ultimately decided - after much debate - that it was better to recommend sites that had already been touched by industry. In their final analysis, they recommended three former phosphate tracts in southwest Polk County. They believed it was best, from both an environmental and economic standpoint, to place previously mined phosphate land back into productive use.

With that recommendation in hand, TEC began negotiations with the land owners. That is how TEC came to select the site TEC has today.

This proactive approach to siting has been very successful for TEC. TEC has established strong support for the project and is maintaining a high level of interaction with the community.

TEC has employed a process of open and regular communications with the local community, our customers, and the media demonstrating that, even in today's environmental climate, TEC can successfully site and build coal-fired generation.

In a recent survey, three out of four of our customers agreed that TEC needed to build this facility. Two out of three think TEC made the right decision to use coal. Many of you know that these results are virtually the opposite of current national trends in public opinion. TEC will continue with our communications-based approach to this project, just as it has with all of its operations within Tampa Electric.

CAPITAL COST

Tampa Electric's total project capital cost was approximately $510 million. At about $2,000/kW, this seems high in comparison to the commercial offerings of other technologies. However, four mitigating factors should be considered:

- Polk Power incorporates first-of-a-kind designs in several plant areas.

- Polk's capital costs include expenses for development and reclamation of the entire 4300 acre site up to its permitted capacity of 1150 MW. The Polk site should satisfy TEC's plant site needs for the next 10 to 20 years.

- Polk has two parallel gas clean-up systems.

- Polk Power is a very clean plant utilizing our most abundant indigenous fuel resource, coal. It incorporates state-of-the-are sulfur removal and recovery systems and air separation unit integration to limit air emissions and a first-of-a-kind brine concentration unit to recover and reuse all process water.

The next similar plant should be able to build on Polk's experience base to significantly reduce costs in several areas. TEC expects the next generation of IGCC plants to cost between $1200 and $1500 when compared on a consistent basis to other technologies. Given the trend in environmental costs for new plants and the likely long term cost and availability of coal, IGCC appears quite attractive.

TECHNICAL DESCRIPTION

A general flow diagram of the entire process is shown in Figure 1.

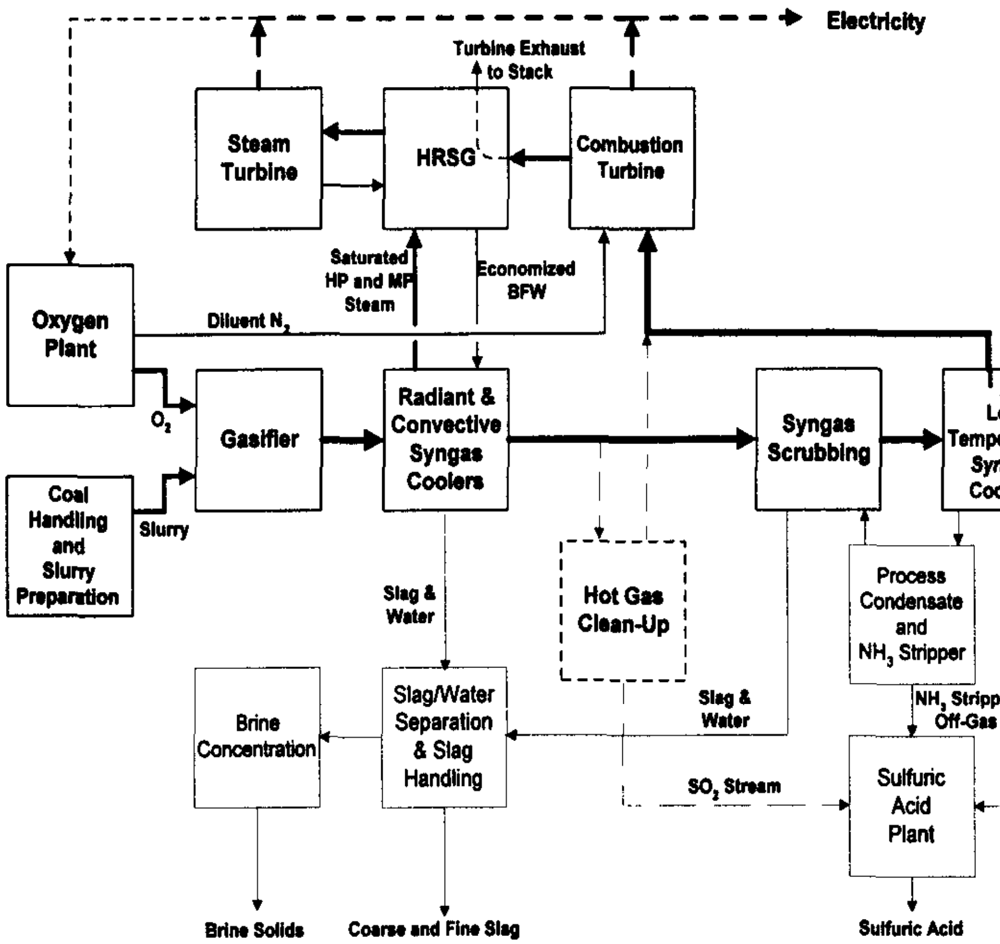


FIGURE 1
Polk Unit #1 IGCC Block Flow Diagram

This unit utilizes commercially available oxygen-blown entrained-flow coal gasification technology licensed by Texaco Development Corporation (Texaco). In this arrangement, coal is ground with water to the desired concentration (60-70 percent solids) in rod mills. The unit is designed to utilize about 2200 tons per day of coal (dry basis). An Air Separation Unit (ASU) separates ambient air into 95% pure oxygen for use in the gasification system and sulfuric acid plant, and nitrogen which is sent to the advanced combustion turbine (CT). The ASU is sized to produce about 2100 tons per day of oxygen and 6300 tons per day of nitrogen. The ASU was provided by Air Products.

This coal/water slurry and the oxygen are then mixed in the gasifier feed injector. This produces syngas with a heat content of about 250 BTU/SCF (LHV). The gasifier is designed to achieve greater than 95 percent carbon conversion in a single pass. The gasifier is a single vessel feeding into one radiant syngas cooler (RSC) which was designed to reduce the gas temperature to 1400°F while producing 1650 psig saturated steam.

After the RSC, the gas is split into two (2) parallel convective syngas coolers (CSC), where the temperature is further reduced to less than 800°F and additional high pressure steam is produced. A 10% slip stream will go to the hot gas clean-up (HGCU) system which is awaiting final commissioning pending catalyst development. Next, the particulates and hydrogen chloride are removed from the syngas by intimate contact with water in the syngas scrubbers. Most of the remaining sensible heat of the syngas is then recovered in low temperature gas cooling by preheating clean syngas and heating steam turbine condensate. A final small trim cooler reduces the syngas temperature to about 100°F for the CGCU system.

All of the syngas is now being processed in a traditional cold gas clean-up (CGCU) system. The CGCU system is a traditional amine scrubber type which removes most of the sulfur from the syngas. Sulfur is recovered in the form of sulfuric acid. The sulfuric acid plant was provided by Monsanto. Sulfuric acid has a ready market in the phosphate industry in the central Florida area. It is expected that the annual production of 45,000 tons of sulfuric acid produced by this 250 MW (net) IGCC unit will have minimal impact on the price and availability of sulfuric acid in the phosphate industry.

Most of the ungasified material in the coal exits the bottom of the RSC into the slag lockhopper where it is mixed with water. These solids generally consist of slag and uncombusted coal products. As they exit the slag lockhopper, these non-leachable products are saleable for blasting grit, roofing tiles, and construction building products. TEC has been marketing slag from its existing units for such uses for over 25 years.

All of the water from the gasification process is cleaned and recycled, thereby creating no requirement for discharging process water from the gasification system. To prevent the build-up of chlorides in the process water system, a brine concentration unit removes them in the form of marketable salts.

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and electric generators. The combined cycle power block is provided by General Electric.

The CT is an advanced GE 7F machine adapted for syngas and distillate fuel firing. The initial startup of the power plant is carried out on low sulfur No. 2 fuel oil. Transfer to syngas occurs upon establishment of fuel production from the gasification plant. The exhaust gas from the CT passes through the HRSG for heat recovery, and leaves the system via the HRSG stack.

Emissions from the HRSG stack are primarily SO_2 and NO_x with lesser quantities of CO, VOC, and particulate matter (PM). SO_2 emissions are from sulfur species in the syngas which are not removed in the CGCU system. The CT uses nitrogen addition to control NO_x emissions during syngas firing. Nitrogen acts as a diluent to lower peak flame temperatures and reduce NO_x formation without the water consumption and treatment/disposal requirements associated with water or steam injection NO_x control methods. Maximum nitrogen diluent is injected to minimize NO_x exhaust concentrations consistent with safe and stable operation of the CT. Water injection is employed to control NO_x emissions when backup distillate fuel oil is used.

The HRSG is installed in the CT exhaust in a traditional combined cycle arrangement to provide superheated steam to the 130 MW ST. No auxiliary firing is done in the HRSG system. The HRSG high and medium pressure steam production is augmented by steam produced from the coal gasification plant's syngas coolers (HP and MP steam) and sulfuric acid plant (MP steam). All steam superheating and reheating is performed in the HRSG before the steam is delivered to the ST.

The ST is a double-flow reheat turbine with low pressure crossover extraction. The ST and associated generator are designed specifically for highly efficient combined cycle operation with nominal turbine inlet throttle steam conditions of approximately 1450 psig and 1000°F with 1000°F reheat inlet temperature.

The heart of the overall project is the integration of the various pieces of hardware and systems to increase overall cycle effectiveness and efficiency. In our arrangement, benefits are derived from using the experience of other IGCC projects, such as the Cool Water Coal Gasification Program, to optimize the flows from different subsystems. For example, low pressure steam from the HRSG and extraction steam from the ST supply heat to the gasification facilities for process use. The HRSG also receives steam energy from the syngas coolers and sulfuric acid plant to supplement the steam cycle power output. This steam is generated using boiler feedwater which had been economized in the HRSG. Additional low energy integration occurs between the HRSG and the gasification plant. Condensate from the ST condenser is returned to the HRSG/integral deaerator by way of the gasification area, where condensate preheating occurs by recovering low level heat. Probably the most novel integration concept in this project is our use of the ASU. This system provides oxygen to the gasifier in the traditional arrangement, while simultaneously using what is normally excess or wasted nitrogen to increase power output and improve cycle efficiency and also lower NO_x formation.

Part of our cooperative agreement with DOE is a four-year demonstration phase. During the first two years of this period, it is planned that four different types of coals will be tested in the operating IGCC power plant. The results of these tests will compare this unit's efficiency, operability and costs, and report on each of these test coals against the design basis coal, a Pittsburgh #8. These results should provide a menu of operating parameters and costs which can be used by utilities in the future as they make their selection on methods for satisfying their generation needs, in compliance with environmental regulations.

II. RELIABILITY GROWTH AND LOST PRODUCTION CAUSES

Table 1 on the next page identifies some of the major accomplishments (☺) and setbacks (☹) in the operational history of Polk Power Station in chronological order. Table 2 on the following page summarizes the causes for all lost gasifier production since gasifier Run 21 which ended on December 23, 1996. The gasifier outage causes prior to Run 21 were identified and discussed in our paper at last year's conference.

All major setbacks in the gasification area to date have been overcome and the less severe problems are being systematically addressed. This has led to gasifier on-stream factors in excess of 70% for the last two quarters (the 6th and 7th quarters of the plant's operation) as shown in Figure 2, In addition, the combined cycle has demonstrated strong availability and availability growth in the last three quarters. Together, these pave the way to meeting our ultimate commercial IGCC availability targets.

Figure 2
Gasifier On-Stream and Combined Cycle Availability Factors

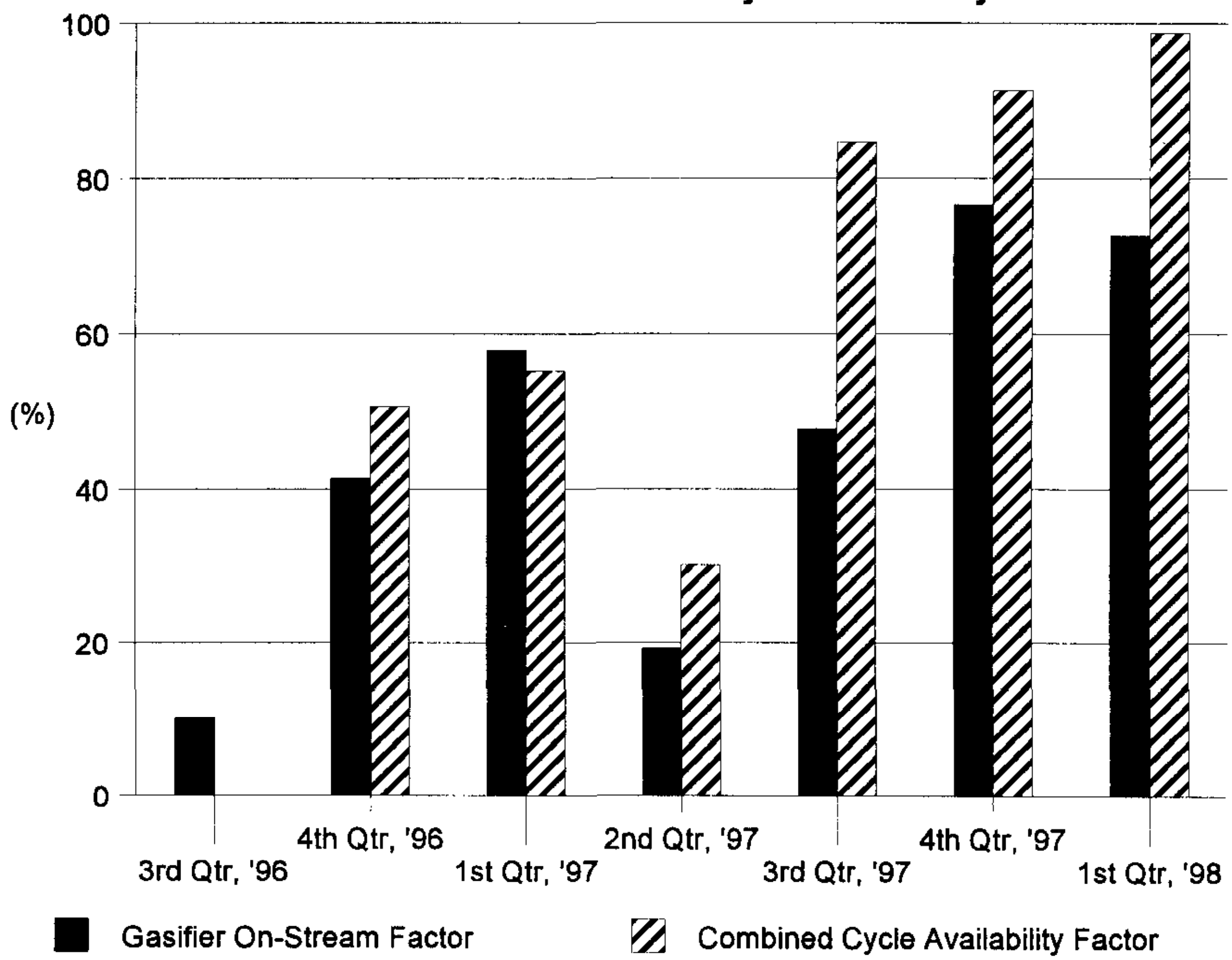


TABLE 1 Significant Events and Dates in Polk's Operating History	
☺ First Syngas Production -Record First Run (21.5 Hr) for Texaco Coal Gasifier	July 19, 1996
☹ First of Four Forced Outages Due to Raw/Clean Gas Exchanger Plugging	Sept 1, 1996
☺ First Syngas to Combustion Turbine	Sept 12, 1996
☺ All Systems Commissioned, Commercial Operation Initiated	Sept 30, 1996
☺ Procedures Developed to Mitigate Raw/Clean Gas Exchanger Plugging	Oct 21, 1996
☺ Record Gasifier Run Completed (28.9 Days)	Jan 22, 1997
☹ Cracks Observed In Clean Syngas Line Strainer - Strainer Removed	Feb 13, 1997
☹ First Forced Outage and CT Damage Due to Raw/Clean Gas Exchanger Leak	Mar 16, 1997
☺ Raw/Clean Gas Exchangers Removed, Clean Syngas Strainer Reinstalled	July 2, 1997
☺ O&M Procedures for Syngas Line and Strainer Cleaning Implemented	July 17, 1997
☹ First of Two Forced Outages Due to RSC Dome Seal Leak	Aug 26, 1997
☺ First Hot Restart Attempt Was Successful	Oct 15, 1997
☺ Record Gasifier Run Completed (35.5 Days)	Jan 3, 1998
☺ Operating Procedures Developed to Correct Dome Seal Leaks On-Line	Mar 11, 1998

Early Successes First syngas was produced on July 19, 1996. The first gasifier run lasted 21.5 hours which set the longevity record for first run of a solid fuel Texaco gasifier. Syngas was first fired in the combustion turbine on September 12, 1996. All plant systems had been successfully commissioned by the end of the third quarter of 1996, so Polk Power Station Unit #1 was placed in commercial operation on September 30, 1996.

Raw Gas/Clean Gas Exchanger Plugging One notable setback in Polk Power's early operating history was plugging of the raw gas/clean gas exchangers with flyash. The first of three forced gasifier outages due to this plugging occurred on September 1, 1996, and this negatively impacted gasifier on-stream time for the next two months. However, by late October, 1996, operating procedures were developed to significantly reduce the rate of plugging. This was discussed at last year's conference.

Reliability Improvement In Late 1996 and Early 1997 Solving the raw gas/clean gas exchanger plugging problem in October, 1996, led to healthy reliability growth in the fourth quarter of 1996 and the first quarter of 1997. One significant accomplishment during this period was a record gasifier run of almost one month duration. This record run ended on January 22, 1997, and was in progress during last year's conference.

TABLE 2
Lost Production Summary - Gasifier Runs 21-50

EVENT / CAUSE	FORCED GASIFIER OUTAGES	RESULTING GASIFIER OUTAGE DAYS	REMEDIAL ACTION
PARTICULATES IN SYNGAS TO TURBINE Raw/Clean Gas Exchanger Leaks and Pipe Scale "Y" Strainer Failure or Pluggage Turbine Damage on 2 Occasions	4	110	 Raw/Clean Gas Exchangers Removed Strainer Repaired & Returned to Service Larger Permanent Filter Being Installed
RSC DOME SEAL LEAKS	2	43	Improved Seal Designs Operating Procedures Developed
BLACK WATER PIPING EROSION Specific Locations	8	15	Harder Materials Piping System Configuration Changes On-Line Replacement
FUEL CHARACTERISTIC CHANGES	3	12	Fines System Upgrade Equipment Internal Modifications Experience
2 of a Kind Incidents Transmission System Voltage Swings Slag Crusher Seal Valve Alignment at Startup	6	6	 Trip Circuitry Changes Improved Crusher Seal Design Experience
MISCELLANEOUS FORCED OUTAGES, OUTAGE EXTENSIONS, AND MAINTENANCE OUTAGES	7	27	Various Mechanical Improvements, Controls Modifications, and Procedural Changes

Particulates to Combustion Turbine Polk's most serious cause of lost production was particulate contamination of the "clean" syngas to the combustion turbine. It caused 110 days of lost gasifier production, mostly in the second quarter of 1997, and led to 4 forced gasifier outages and significant combustion turbine damage on two occasions. An event which indirectly led to the turbine damage occurred on February 13, 1997. While performing a routine preventive maintenance inspection during an outage, cracks were found in the bodies of the Y strainers on both diluent nitrogen and syngas lines to the combustion turbine. The Y strainers were to catch large objects such as nuts and bolts left over from construction which could cause foreign object damage (FOD) to the turbine. Nothing had ever been found in the strainers, and the system had operated long enough that we believed any significant material would have already been removed. Also, repair time for the strainer bodies was quoted as 6 months. For these reasons, we elected to continue operation without the strainers while they were being repaired. Had the strainers been in place, they might have prevented or minimized the turbine damage which occurred on 2 occasions, first due to flyash from the first gas/gas exchanger tube failure on March 16, 1997, and the second from a combination of pipe scale and flyash from the third gas/gas exchanger tube failure on May 26, 1997.

On March 16, 1997, 2 days into the 25th gasifier run and less than one month after the "Y" strainers were removed, a tube failed in the second stage of the raw gas/clean gas exchanger . This exchanger preheated the clean syngas to the turbine with heat from the hot particulate laden raw syngas from the convective boiler. The existing leak detection system did identify the leak, and we were just about to transfer the turbine to distillate fuel when the turbine tripped automatically.

Subsequent inspection revealed significant ash deposits on the turbine blades and combustion liners. The cause of the tube failure in the raw gas/clean gas exchanger was stress corrosion cracking. The stress corrosion cracks probably had formed at a site of residual local stresses from fabrication. The corrosion itself was a form of down-time corrosion induced by the hydrophilic ash deposits which had plugged the exchanger in September and October of 1996. Thorough inspection revealed no other incipient stress corrosion cracks, but did confirm that there was general pitting of the tubes. So the shell with the failed tube (which also had the worst pitting) was removed, the worst pitted tubes in the other gas/gas exchanger shells were plugged or replaced, the turbine was repaired, and the leak detection system was upgraded.

At startup of the next gasifier run, the leak detection system worked and immediately indicated there was a tube leak before the turbine was transferred to syngas fuel. In this case, the leak was due to damage inflicted on a good tube while an adjacent badly pitted tube was being plugged during the previous outage. The damaged tube was plugged, and the unit was returned to service.

During startup of the subsequent run, an unfortunate combination of circumstances caused us to operate the gasifier in a regime which plugged some of the gas/gas exchanger tubes with ash. This led to high velocities in the remaining tubes. Also, throughout the run, the turbine exhibited problems, even though there was absolutely no indication of a tube leak in the gas/gas exchangers. These problems were not as severe as those which occurred on March 16 which caused the turbine trip, but they were a cause of concern, and as a result, we watched the tube leak indicators closely.

Finally, on May 26, 1997, the 16th day of the run, another raw gas/clean gas exchanger tube began leaking. The leak detection system alerted us to the problem immediately, and we quickly transferred the turbine to distillate fuel. Post shutdown inspection revealed significantly more deposits than we expected, given the very short time the turbine operated on contaminated syngas. Unlike the deposits from the first incident, these deposits consisted primarily of iron with traces of other metals typically found in pipe. There was only a very thin layer of coal ash on top of the largest mass of the deposits. This led us to believe that the most serious problem in this case was pipe scale.

The turbine was again cleaned and repaired, and the remaining 3 shells of the gas/gas exchangers were physically removed. Most importantly, repair of the Y strainers had been expedited and they were returned to service.

After startup of the next run, the syngas strainer plugged with pipe scale several times. The gasifier was finally shut down, the syngas line was thoroughly cleaned, and the unit was returned to service on July 17, 1997. The strainer still occasionally plugs with pipe scale, but it is possible to clean it in about 2 hours and return the combustion turbine to syngas service without shutting down the gasifier. The existing strainer has relatively little filtration surface, and we are now installing a larger filter to reduce the frequency of strainer cleaning.

Radiant Syngas Cooler Dome Seal Leaks Polk's second most serious cause of lost production was syngas leakage through seals in the dome area of the radiant syngas cooler. Severe leaks would result in hot syngas impinging on the vessel shell, and could cause shell failure if they were allowed to persist. The first incident of seal leakage causing lost production occurred on August 26, 1997, and resulted in a 29 day outage. This severely impacted gasifier availability for the third quarter of 1997. The seal was modified during the outage.

The only other incident of lost production due to a seal leak in the RSC dome occurred in November, 1997, and led to a 14 day outage. This second failure was in a different, more accessible seal. This seal design was also modified, but some leakage was still observed during subsequent gasifier runs.

Finally, a severe seal leak began on March 11, 1998. This time, however, we developed operating procedures to stop the leak without having to shut down the gasifier and enter the vessel. These same procedures have proven effective on four subsequent occasions. Design modifications are clearly indicated in the seal area at the next major outage, but until then, these new operating procedures should eliminate further lost production from this source.

Another Record Run The run following the second outage for an RSC dome seal leak established a new gasifier run length record: 35½ days. This run ended on January 3, 1998. One particularly encouraging factor from this run is that none of the gasification system components which were expected to ultimately be run limiting showed excessive wear. This opens the door to even longer continuous gasifier runs.

Hot Restarts The conventional method of starting a Texaco gasifier consists of first preheating the refractory liner with a "Preheat Burner", then changing to the "Process Feed Injector" just prior to startup. This preheating and changing burners is time consuming when the gasifier has experienced a nuisance shutdown whose cause can be easily identified and corrected. The average duration of such outages was 30.5 hours at Polk. To shorten this time, the Polk staff has been working on developing the controls and procedures to execute "hot restarts" since early operation. Hot restarts eliminate the preheating and burner changes. The first attempt at a hot restart on October 15, 1997, was successful. Since then, we have conducted eleven successful hot restarts with an average gasifier outage duration of only 5 hours. We have shown it is even possible to perform some minor maintenance during these outages which cannot be performed when the gasifier is on line. The development of the hot restart procedure is estimated to have saved 275 hours of lost gasifier production in six months we have been using it. This equates to over a 6% boost in gasifier on-stream factor. Development of the procedure contributed significantly to the gasifier reliability growth we experienced in the fourth quarter of 1977 and the first quarter of 1998.

Other Causes of Forced Outages and Lost Gasifier Production

Black Water Piping Erosion Black water is the particulate laden water associated primarily with the syngas scrubbers. Since last year's conference, leaks in black water piping caused by localized erosion have been responsible for 8 forced gasifier outages and 15 days of lost gasifier production. This is the third most serious cause of production loss in this time period. These leaks have been at five specific pipe fittings. We are testing special hard surfaced fittings in these areas. Also, some more general piping system modifications are scheduled for implementation in the next major outage. In the mean time, our staff has become very adept at changing or repairing the troublesome fittings on-line or during brief hot restart outages to minimize lost production.

Fuel Characteristic Changes Seven different fuels have been gasified at Polk Power Station to date in an attempt to identify an economically optimum feedstock. Specific results of the alternate fuel tests will be discussed in the next section of this paper. Unfortunately, changes in fuels often result in some unpleasant surprises. Changes in fuel reactivity and ash characteristics have led to three gasifier forced outages and 12 days of lost gasifier production. We are making some minor internal modifications to some of our equipment and expanding our capability to handle fines to enable us to better accommodate a wider range of fuel properties. Equally important, with each new fuel, TEC is broadening its experience base to reduce the frequency and impact of upsets brought on by expected as well as unexpected changes in feedstock properties.

Transmission System Voltage Swings We have incurred two gasifier forced outages in the most recent five quarters due to transmission system upsets. This is a dramatic improvement. At the last conference, we reported having experienced four forced outages from such upsets in the two preceeding quarters. We have identified and corrected several weaknesses in the trip circuitry, and are continuing to make improvements in this area. However, occasional trips due to transmission system problems are inevitable in the Tampa area, the lightning capital of the world.

Slag Crusher Seal Slag from the gasifier falls into the RSC sump and is removed in a lockhopper system. Most slag particles are "M & M" size or smaller, but a slag crusher at the bottom of the RSC sump handles the occasional larger slag masses. The slag crusher is a shaft driven device, and failures of its shaft seal have caused two brief forced gasifier outages. This is an extremely hostile environment. Seal design modifications have been made and more modifications are planned in this area for the next major outage.

Valve Line-Up Improper valve line-up prior to gasifier lightoff has been responsible for two gasifier forced outages since the beginning of 1997. In each case, the gasifier safety system quickly and safely terminated the runs without any equipment damage or injury. We expect to eliminate this as a cause of lost production as we gain experience and as our startup check lists are fine-tuned.

***Miscellaneous Forced Outages, Forced Outage Extensions, and Maintenance Outage* Extensions** Seven miscellaneous one-of-a-kind forced gasifier outages have occurred since the beginning of 1977, two forced outage extensions have occurred, and some outages have been extended to perform preventative maintenance. All together, these have resulted in 27 days of lost production. We have taken appropriate corrective action wherever practical, so we expect improvement in this category. However, such sources of lost production can never be entirely eliminated.

III. ALTERNATE FUEL TESTS

Polk Power Station's design coal is a Pittsburgh #8, and the unit operated exclusively on this coal for the first 10 months. However, beginning in May, 1997, we conducted test campaigns on four alternate fuels in an attempt to find the lowest overall cost feedstock and to satisfy DOE requirements. Results from these tests are compared in this section.

Several key properties of gasifier feedstocks which have a known impact on Polk's IGCC performance are easily determined by simple laboratory tests. The importance of these properties is discussed below. Thier values for the feedstocks tested at Polk and the test durations are shown in Table 3 (next page).

1) SULFUR CONTENT Polk's CGCU and sulfuric acid plant are designed to accommodate syngas produced from feedstocks containing up to 3½% sulfur. The tests have shown that operation on feedstocks with significantly higher sulfur content would requre expensive modifications.

2) ASH CONTENT Polk's slag removal system limits us to feedstocks with about 12% ash content. High ash content fuels also have an adverse impact on heat rate.

3) HEATING VALUE The size of Polk's oxygen supply and slurry delivery systems preclude the plant from producing enough syngas to fully load the combustion turbine if the gasifier feedstock has a higher heating value less than approximately 12,500 BTU/Lb.

4) ASH FUSION TEMPERATURE Polk's Texaco gasifier is a slagging gasifier, which means that operation must occur at a temperature high enough for the coal's mineral matter to melt and flow freely. The ASTM ash fusion temperature measured under reducing conditions correlates reasonably well with the minimum viable gasifier operating temperature for successful slagging operation.

5) CHLORINE CONTENT Most of the chlorine in the gasifier's feedstock finds it way into the process water system, and Polk's metallurgy in this area imposes a limit on its allowable chloride content. To keep the process water system below this limit, a continuous blowdown stream is withdrawn to the brine concentration unit. Hence, the capacity of the brine concentration unit ultimately limits the chlorine content of Polk's feedstocks to about 0.15%.

TABLE 3
Polk Coal Properties

Coal Seam	Pittsburgh 8 #1 (First Base)	Pittsburgh 8 #2	Pittsburgh 8 #3	Kentucky 11 (Current Base)	Illinois 6
Days of Operation	183	15	25	5	25
ASTM ASH FUSION (Fluid/Reducing, Deg F)	2400	2200	2230	2295	2220
Wt % Sulfur (Dry)	2.5	2.8	2.0	3.0	3.3
Wt % Ash (Dry Basis)	9.0	11.3	9.6	7.0	12.1
HHV (Dry BTU/Lb)	13500	13350	13500	13300	12500
Wt % Cl (Dry Basis)	.10	.08	.10	.12	.14

The following are four other key properties of a fuel for the Texaco Process as applied at Polk Power Station. These properties cannot be accurately estimated from laboratory data, but must be determined through plant testing. The alternate fuel test campaigns at Polk attempted to at least semi-quantitatively determine each of these properties.

1) **"SLURRYABILITY" How well does it slurry?** The ability of a fuel to be processed into a high concentration slurry improves efficiency and assures that the plant will be able to operate at full load, unconstrained by slurry feed pump or oxygen supply limits. If additive is required, it increases costs, which must be balanced against the efficiency or output gains it provides.

2) **"REACTIVITY" (Carbon Conversion) How reactive is it?** Highly reactive coals provide high carbon conversion at moderate gasifier temperatures. This improves overall system efficiency and reduces the amount of solids (flyash) which must be processed or handled without sacrificing refractory liner life.

3) **"SLAG AGGRESSION" How aggressive is the slag toward the refractory liner?** Aggressive slags produce high refractory wear rates, even at moderate gasifier temperatures, and the wear rate increases at higher temperatures. Given the high cost of refractory replacement, there is a very strong economic incentive to select coals with non-aggressive slags and to operate the gasifier at low temperatures to minimize refractory wear rate.

4) **"SGC FOULING" How badly does it foul the Syngas Coolers?** Severe fouling would inhibit heat transfer, reducing efficiency and causing problems in the syngas scrubbers and low temperature gas cooling.

SLURRYABILITY

Polk's slurry preparation system consists of 2 rod mills, each of which has recently demonstrated the capacity to process up to 120,000 lb/hr of as-received coal (1440 short tons/day each or 2880 tons/day total) under ideal conditions. The slurry is discharged from the mills through trommel screens into relatively small "Mill Discharge Tanks". From the Mill Discharge Tanks, it is pumped across screens into one of the two "Run Tanks". A single pump delivers the slurry from a Run Tank to the Gasifier.

The following discussion and Table 4 summarize our slurry preparation experiences on the various coals. Virtually all operation to date has been between 59% and 63% slurry concentration. The main requirement is that the slurry concentration must be high enough that the slurry feed pump can deliver sufficient slurry to produce enough syngas fuel to fully load the combustion turbine.

For the **base Pittsburgh 8 coal**, we typically targeted 61% to 62% concentration, although up to 63% slurries were produced on this coal without the use of slurry additive. We intentionally operated at low concentrations since this coal's reactivity is relatively low. Lower concentration slurry permitted reactor operation at the higher oxygen to fuel ratios needed for 95% carbon conversion (our fines handling system cannot accommodate lower conversion at full load) and also at moderate temperatures for reasonable liner life.

The **second Pittsburgh 8** coal we tested had similar slurry characteristics to the base coal. However, it had significantly lower reactivity than the base coal and its slag was much more aggressive toward the gasifier refractory. Consequently, it was an unacceptable feedstock for our unit.

The **third Pittsburgh 8** tested could not be made to yield a slurry over 61.5% concentration, even with the use of additive. The slurry appeared unstable. This feed coal was finer than usual, so our grind size was finer (the rod mills are fixed speed). This may have contributed to the problem.

A **Kentucky 11** was the first alternate coal tested. A 61.5% concentration slurry can be produced without additive, which was not quite sufficient to achieve full load. Higher concentrations require the use of additive. Since this coal has other excellent properties, we have recently converted to it as our new base feedstock. We are now producing 62.8% concentration slurries with additive which does enable us to fully load the combustion turbine.

With the help of additive, we could produce slightly over 62% concentration slurries of the **Illinois 6** coal we tested, which was not adequate to achieve full load. This coal has other excellent properties, and is one of TECO's long term contract coals. Hopefully we will have future opportunities to work with it to achieve the 63.0% slurry concentration needed for full load operation.

TABLE 4
Slurry Concentrations

Coal	Concentration Needed for Full Load	Concentration Achieved	Comments
Pittsburgh 8 #1	59.6	>62.5	Fines Limit
Pittsburgh 8 #2	61.7	>62.5	Unacceptable Fuel
Pittsburgh 8 #3	60.4	61.5 (+)	Unstable Slurry
Kentucky 11	62.8	62.8 (+)	
Illinois 6	63.0	62.1 (+)	

In above table, " (+)" indicates that additive was needed to produce the slurry concentrations shown.

SLAG AGGRESSION and REACTIVITY (Carbon Conversion)

These two very important dimensions of a coal's performance are discussed together in this section of the paper since they are both intimately related to the key controlled variable for gasifier operation - the temperature. The temperature must be low enough to provide a reasonable liner life, yet high enough to yield acceptable carbon conversion and low enough slag viscosity so it will flow freely.

In Figure 3, gasifier's refractory liner life projected from measurements made during the tests is plotted versus the difference between gasifier operating temperature and the ASTM ash fluid temperature (reducing conditions). This parameter was chosen for the abscissa since the ASTM test is inexpensive, standardized, the results are consistent, and the difference between it and the gasifier operating temperature facilitates the comparison between fuels of differing ash composition. It also provides a quick visual indication of how much cooler we could operate the gasifier without encountering problems with insufficient slag fluidity.

In Figure 4, carbon conversion is plotted directly against gasifier operating temperature. The temperature (instead of oxygen to fuel ratio) was chosen as the abscissa for this figure since in practice temperature is the parameter which we attempt to measure and control in real time operation.

The points connected by lines on the figures are results from sequential tests, or, at least tests where we were quite sure that we were processing the same feedstock. These points show the expected trends: lower liner life and higher conversion at higher temperatures. The fuels are discussed below generally in the order of "best" to "worst" in the remainder of this section.

Illinois 6: This coal was run well above its ash fusion temperature. At this temperature, we expected high refractory losses, but that was not the case. Conversion was also very high (97.5%), indicating that optimal operation would be at significantly lower temperature, where we should achieve well over 3 year liner life while still maintaining very acceptable carbon conversion.

Kentucky 11 (Current Base Coal): This coal demonstrated relatively long liner life and reasonable conversion over a wide temperature range. This combination of properties, along with the ability to produce a sufficiently high slurry concentrations to fully load the combustion turbine and several other technical and commercial factors led us to select this coal as the Polk's base fuel for much of 1998.

Pittsburgh 8 #1 (First Base Coal): The two connected points (sequential runs) show marginally acceptable liner life, while the one other point shows unacceptably low liner life. This coal was supplied from a processing plant which handles coals from more than one local mine, so it is very possible that the mineral matter was indeed different for the outlying point. Carbon conversion values were consistent, but only marginally acceptable for all three points. This Pittsburgh 8 appeared to be rather inconsistent with a very small commercially viable gasifier operating range. Furthermore, its availability was limited and commercial terms were not very attractive. All these factors prompted us to change to the Kentucky 11 as our new base fuel.

Pittsburgh 8 #3: This coal had comparable reactivity to the base Pittsburgh #8. However, liner life projections at gasifier temperatures high enough for acceptable carbon conversion are considerably worse. Therefore, this is not an attractive feedstock.

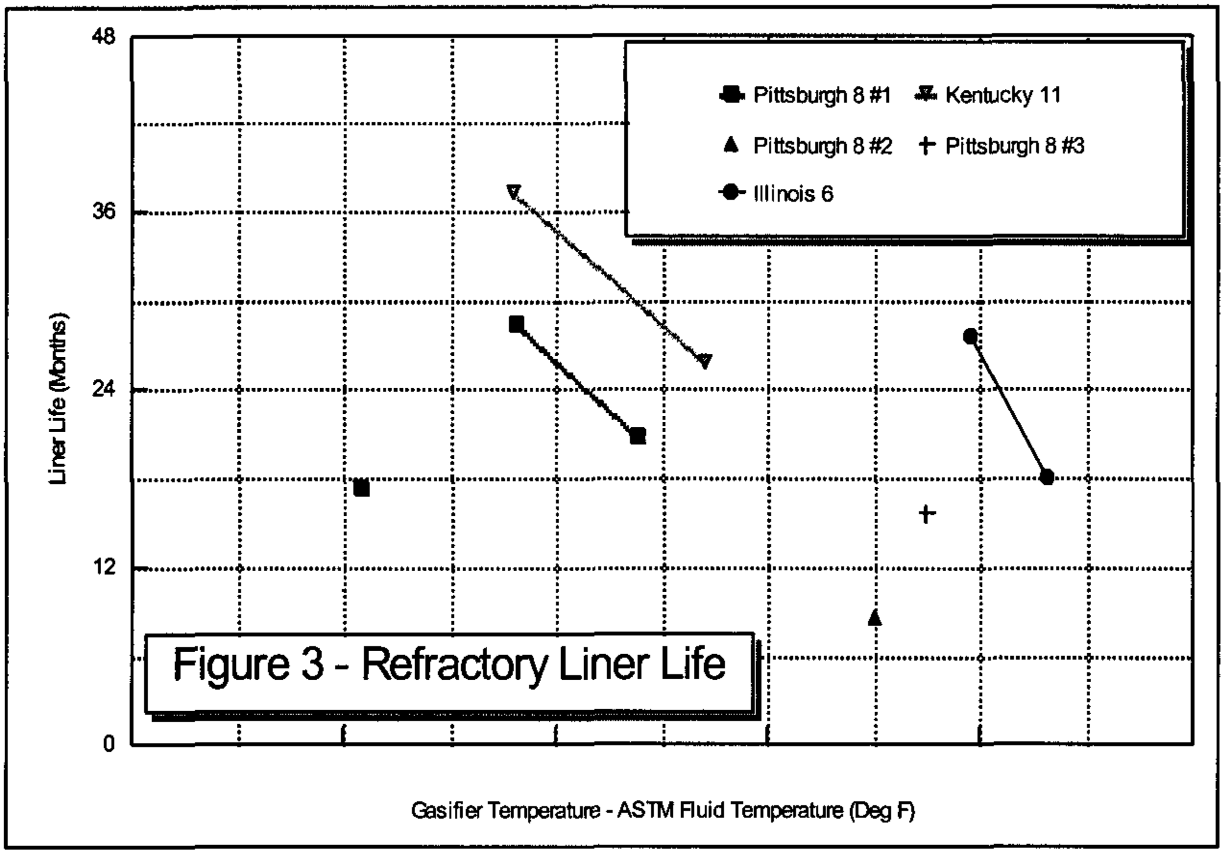


Figure 3 - Refractory Liner Life

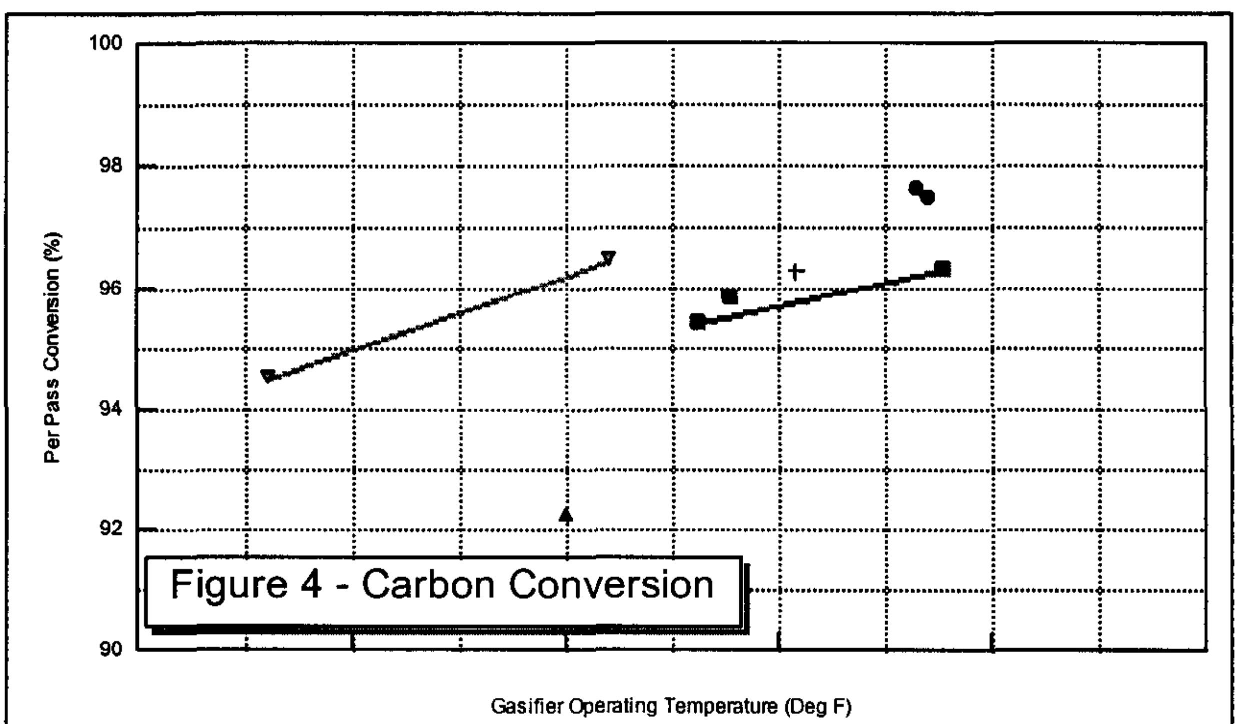


Figure 4 - Carbon Conversion

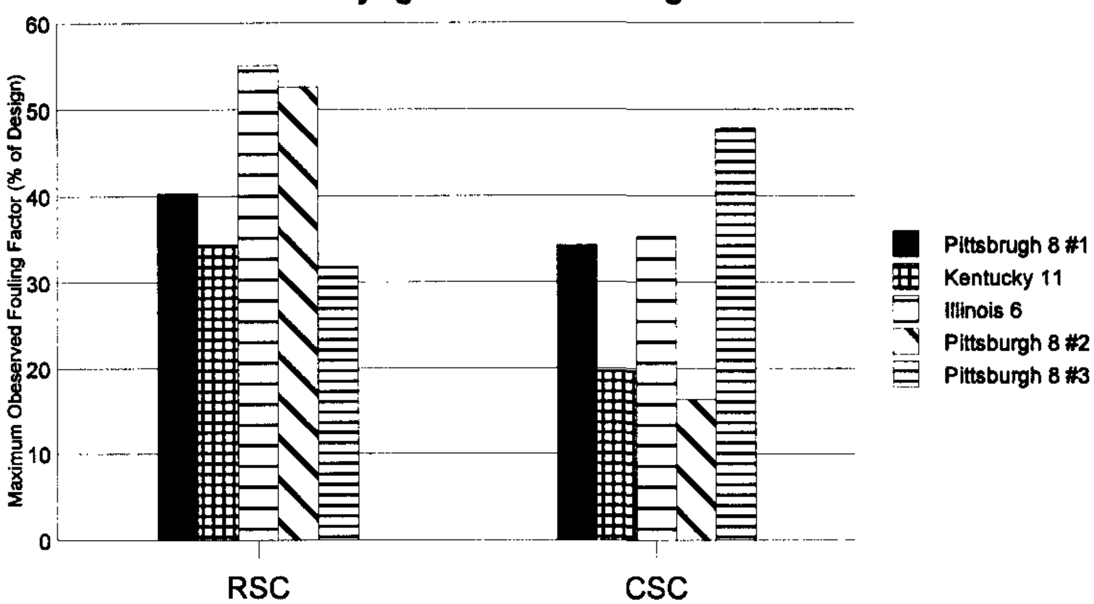
Pittsburgh 8 #2: This coal demonstrated low liner life, but this was consistent with its operation well above its fusion temperature. Lower temperature operation would probably have provided an acceptable liner life, but it could not be operated at lower temperature because carbon conversion was unacceptably low, even at the higher temperature. This is by far the worst performer of the three Pittsburgh 8 coals tested, and there are no pricing or other commercial incentives to utilize it. Consequently, Pittsburgh 8 #2 coal appears to have has no commercially viable operating range (or even point) in Polk's gasifier, so it is considered to be an unacceptable feedstock.

SGC FOULING

Radiant Syngas Cooler (RSC) and Convective Syngas Cooler (CSC) design fouling factors were based on extensive analysis of data from other Texaco coal gasification plants. The following Figure 5 shows the RSC and CSC fouling factors as a fraction of their design values.

FIGURE 5

Syngas Cooler Fouling Factors



All fouling factors were significantly lower than design. This is particularly remarkable in the case of the RSC since the RSC design data was taken from units which always utilized soot blowing, but no soot blowing has been practiced at Polk. This difference is possibly due to Polk's different metallurgy or geometry and fluid dynamics.

IV. PLANS FOR 1998

The following are some of the significant activities planned for Polk Power Station for 1998. There are several activities in progress or scheduled to address each of these goals.

1) Reduce forced gasifier outage frequency and duration due to **black water piping leaks** through piping system modifications. This is an ongoing effort, but some significant modifications will be implemented in a two week outage scheduled for early May, 1998.

2) Improve design of **seals in the RSC head area** to eliminate leakage. An improved design will be installed in May, 1998.

3) Implement the revised design for the **fines handling system** to enable operation on a wider range of feedstocks over a wider range of conditions. The alternate fuel tests conducted to date provided the basis for the revised design, and the improved system should be operational by the end of 1998.

4) **Reduce HRSG stack SO_2 emissions** from their present levels. This will be accomplished by completing design modifications already in progress to reduce in hydrogen sulfide (H_2S) content of the clean syngas by improving performance of the existing CGCU. Furthermore, some development work has already resulted in a 30% reduction of carbonyl sulfide (COS) in the syngas. More work to further reduce COS is scheduled throughout the remainder of the year.

5) Upgrade the **brine concentration system** to improve its reliability and lower overall plant heat rate. A comprehensive assessment of the problems in this area and their potential solutions was completed in April, and the recommendations are currently being evaluated.

6) Upgrade the **slag handling system** to reduce O&M costs, to produce a more valuable byproduct slag, and to enable selective recycling of some fractions of the current slag product to reduce heat rate The design for the revised system was based on the alternate fuel test results to date. Process flow diagrams for these design revisions have been completed and detailed design is under way.

7) Complete installation and commissioning of the **clean gas filter** to positively protect the combustion turbine from damage due to particulate contamination of the syngas and to reduce the frequency of combustion turbine operation on distillate fuel to clean the "Y" strainers.

8) Continue **testing of alternate fuels** to lower Polk Power Station's overall busbar cost.

V. CONCLUSIONS

Polk Power Station's performance in the first three quarters of 1997 was impacted by particulate contamination of the clean syngas and leakage in the RSC dome area. These problems have been largely resolved. Consequently, very positive results were achieved in the most recent six months of operation. We expect further improvement as a result of the activities planned for 1998. These activities should bring us very close to reaching our ultimate commercial goals in the areas of high reliability and efficiency with low emissions and busbar cost.

OPERATING EXPERIENCE AT THE WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

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ABSTRACT

The Wabash River Coal Gasification Repowering Project (WRCGRP), a joint venture between Destec Energy, Inc., and PSI Energy, Inc., began commercial operation in November of 1995. The Project, selected by the United States Department of Energy (DOE) under the Clean Coal Program (Round IV) represents the largest operating coal-gasification combined-cycle plant in the world. This demonstration project has allowed PSI Energy to repower a 1950s vintage steam turbine and install a new syngas-fired combustion turbine to provide 262 MW (net) of electricity in a clean, efficient manner in a commercial utility setting while utilizing locally mined high-sulfur Indiana bituminous coal. In doing so, the project is also demonstrating some novel technology while advancing the commercialization of integrated coal-gasification combined-cycle technology. This paper will discuss the improvements to the process and operations of the gasification and power block as a result of experiences gained from early commercial operating experience of the Wabash Project.

I. INTRODUCTION

When the Wabash River Coal Gasification Repowering Project Joint Venture (JV) signed the Cooperative Agreement with the U.S. Department of Energy (DOE) in July 1992, this marked the beginning of a truly beneficial alignment amongst the entities involved. PSI needed a clean, low-cost, energy-efficient baseload capacity addition that would function as a substantial element of their plan to comply with the requirements of the Clean Air Act. Also important was this project's ability to process locally mined (Indiana) medium-high sulfur coal. Finally, PSI needed a project that would pass the approval of the Indiana Utility Regulatory Commission as a low-cost option for baseload capacity addition.

Encouraged by the data and experience gained at its Louisiana Gasification Technology, Inc., plant (LGTI) and by the DOE Clean Coal Technology Program, Destec was interested in advancing its gasification technology to the next generation to enhance the competitive position of gasification technology for future IGCC projects.

The DOE, through its Clean Coal Round IV Program, wanted a commercial demonstration of a clean coal technology to abate the barriers to commercialization of clean coal technologies and gain data to enable power generators to make informed decisions concerning utilization of clean coal technologies.

Through the Wabash River Coal Gasification Repowering Project, the needs of the participants and the DOE are being met with this 262-MW commercial power plant. This project is demonstrating a clean, highly efficient technology that meets today's energy demand and tomorrow's (year 2000) clean air requirements.

II. OVERVIEW

The project participants, Destec Energy, Inc. (Destec) of Houston, Texas, and PSI Energy, Inc., (PSI) of Plainfield, Indiana, formed the JV to participate in DOE's Clean Coal Technology (CCT) program to demonstrate the coal-gasification repowering of an existing generating unit impacted by the Clean Air Act. The participants jointly developed, separately designed, constructed, own, and are now operating an integrated coal-gasification combined-cycle power plant, using Destec's coal gasification technology to repower the oldest of the six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. Destec's gasification process is integrated with a new General Electric 7 FA combustion turbine generator and a Foster Wheeler heat recovery steam generator in the repowering of a 1950s-vintage Westinghouse steam turbine generator using pre-existing coal handling facilities, interconnections, and other auxiliaries.

The project is currently in the third year of a three-year Demonstration Period under the DOE CCT program. The early operation of the project, which is now the world's largest single-train coal-gasification combined-cycle plant operating commercially, has demonstrated the ability to run at full load capability while meeting the environmental requirements for sulfur and NO_x emissions. CINergy, PSI's parent company, dispatches power from the project, with a demonstrated heat rate of under 9,000 Btu/kWh (HHV), second behind their hydro facilities on the basis of environmental emissions and efficiency.

III. BACKGROUND

Destec Gasification Technology Evolution

The development of the Destec gasification process began in the early 1970s. Destec's original parent company, Dow Chemical, wanted to diversify its fuel base from natural gas to lignite and coal for its power-intensive chlor-alkali processes and began to develop the gasification process through basic R&D and pilot plants. The first commercial gasification plant followed, Louisiana Gasification Technology, Inc. (LGTI), in Plaquemine, LA. This project operated from the second quarter 1987 until the third quarter 1995 under subsidy from the Synthetic Fuels Corporation and later the Treasury Department. When Destec was formed in 1989, the gasification technology was transferred from Dow Chemical to Destec. In June of 1997, Destec

Energy was purchased by and has now become a wholly owned subsidiary of NGC Corporation, a leading gatherer, processor, transporter and marketer of energy products and services in North America and select markets worldwide.

Wabash Project Development

Destec approached PSI in early 1990 to initiate discussions concerning the DOE Clean Coal Technology Round IV program solicitation. Through the Wabash River Coal Gasification Repowering Project Joint Venture, the project submittal was made. In September 1991, the Project was among nine projects selected from 33 proposals. The Project was selected to demonstrate the integration of Destec's gasification process with a new GE 7 FA combustion turbine generator and a heat recovery steam generator (HRSG) in the repowering of an aged steam turbine generator to achieve improved efficiency and reduced emissions.

Goals of Participants

The goals of the participants within the Project are summarized as follows:

- PSI wants to demonstrate an alternative technology for new units and repowering of existing units. Also, PSI is incorporating this IGCC power plant into their system and wants to demonstrate this as a reliable and cost-effective element of their baseload generation capability.
- Destec is also demonstrating the operability, cost effectiveness and economic viability of its gasification technology in a commercial utility setting.
- Destec wants to further enhance its gasification technology's competitive position by demonstrating new techniques and process enhancements as well as substantiate performance expectations and capital and operating costs.
- The DOE wants to abate the barriers to commercializing clean coal technologies, particularly gasification and repowering applications, and otherwise enable power generators to make informed commercial decisions concerning the utilization of clean coal technology.

Project Organization, Commercial Structure, and Costs

There are two major agreements, which establish the basis of the Project. First, the Joint Venture Agreement was created between PSI and Destec to form the Wabash River Coal Gasification Repowering Project Joint Venture in order to administer the project under the DOE Cooperative Agreement. Second, the Gasification Services Agreement (GSA) was developed between PSI and Destec and contains the commercial terms under which the project was developed and is now operated.

PSI Responsibilities:

- build power generation facility to an agreed schedule
- own and operate the power generation facility
- furnish Destec with a site, coal, electric power, storm water and wastewater facilities, and other utilities and services.

Destec Responsibilities:

- build gasification facility to an agreed schedule
- own and operate the gasification facility
- guarantee operating performance of the coal gasification facility, including product and by-product quality
- deliver syngas and steam to the power generation facility

Project Costs

The overall combined cost of the gasification and power generation facilities was $417 million at completion. This cost includes the costs of engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and start-up. This figure includes escalation during the project. The start-up costs include the costs of construction and operations, excluding coal and power, up to the date of commercial operation on December 1, 1995. Soft costs such as legal and financing fees and interest during construction are not included in this figure.

A savings of $30-40 million was realized by the repowering of the existing PSI facility, because the steam turbine, auxiliaries, and coal handling equipment. This probably also reduced the project schedule by as much as a year, because of the simplified permitting effort versus that for a greenfield project.

Two areas of significant impact that increased the cost of the project were unanticipated construction problems and start-up delays. The construction effort was plagued by weather problems in the first nine months of the schedule, and later by labor shortages and construction contractor problems, that led to massive acceleration in the last 25% of the two-year construction schedule. During the combined start-up of the gasification and power generation facilities, certain delays contributed to extension of the project fixed costs that also contributed to the final cost.

Project participants anticipate the costs of future units to be reduced dramatically, to the $1200/kW range for dual train facilities. Advances in turbine technology should bring the installed cost to under $1000/kW for greenfield installations by the year 2000.

IV. REVIEW OF TECHNOLOGY

General Design and Process Flow

The Destec coal gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained-flow gasifier, which uses natural gas for start-up. Coal is milled with water in a rodmill to form a slurry. The slurry is combined with oxygen in mixer nozzles and injected into the first stage of the gasifier, which operates at 2600°F and 400 psig. Oxygen of 95% purity is supplied by a turnkey, Air Liquide, 2,060-ton/day low-pressure cryogenic distillation facility which Destec owns and operates.

In the first stage, coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a taphole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas then flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating valve and to improve overall efficiency.

The syngas then flows to the high-temperature heat-recovery unit (HTHRU), essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier where the carbon in the char is converted into syngas. Filter-element construction and system configuration are proprietary designs that have evolved from full-scale testing at LGTI through improvements during the first two years of operation at Wabash. The syngas is further cooled in a series of heat exchangers, is water scrubbed for chlorides removal and is passed through a catalyst which hydrolyzes carbonyl sulfide into hydrogen sulfide. Hydrogen sulfide is removed using MDEA-based absorber/stripper columns. The "sweet" syngas is then moisturized, preheated, and piped over to the power block.

The key elements of the power block are the General Electric MS 7001 FA high-temperature combustion turbine/generator, the HRSG, and the repowered steam turbine.

The GE 7 FA is a dual-fuel turbine (syngas for operations and No. 2 fuel oil for startup) capable of a nominal 192 MW when firing syngas, attributed to the increased mass flows associated with syngas. Steam injection is used for NOx control, but the steam flow requirement is minimal compared to that of conventional systems because the syngas is moisturized at the gasification facility, making use of low-level heat in the process. The water consumed in this process is continuously made up at the power block by water treatment systems, which clarify and treat river water.

The HRSG for this project is a single-drum design capable of superheating 754,000 lb/hr of high-pressure steam at 1010°F, and 600,820 lb/hr of reheat steam at 1010°F when operating on design-basis syngas. The HRSG configuration was specifically optimized to utilize both the gas-turbine exhaust energy and the heat energy made available in the gasification process. The nature of the gasification process in combination with the need for strict temperature and pressure control of the steam turbine led to a great deal of creative integration between the HRSG and the gasification facility.

The repowered unit, originally installed in 1952, consisted of a conventional coal-fired boiler feeding a Westinghouse reheat steam turbine rated at 99 MW but derated in recent years to 90 MW for environmental dispatch. Repowering involved refurbishing the steam turbine to both extend its life and withstand the increased steam flows and pressures associated with the combined-cycle operation.

The repowered steam turbine produces 104 MW, which combines with the combustion turbine generator's 192 MW and the system's auxiliary load of approximately 34 MW to yield 262 MW (net) to the CINergy grid.

The Air Separation Unit (ASU) provides oxygen and nitrogen for use in the gasification process but is not an integral part of the plant thermal balance. The ASU uses services such as cooling water and steam from the gasification facilities and is operated from the gasification plant control room.

The gasification facility produces two commercial by-products during operation. Sulfur removed as 99.9 percent pure elemental sulfur is marketed to sulfur users. Slag will be marketed as an aggregate in asphalt roads and as structural fill in various types of construction applications.

Technical Advances

Using integrated coal gasification combined-cycle technology to repower a 1950's-vintage coal-fired power generating unit essentially demonstrates a technical advance in and of itself.

More specifically, high energy efficiency and superior environmental performance while using high sulfur bituminous coal are the result of several improvements to Destec's gasification technology, including:

- Hot/Dry Particulate Removal, applied here at full commercial scale.
- Syngas Recycle, which provides fuel and process flexibility while maintaining high efficiency.
- A High-Pressure Boiler, which cools the hot, raw gas by producing steam at a pressure of 1,600 psia.
- A Dedicated Oxygen Plant, which produces 95% pure oxygen for use by the project. Use of 95% purity increases overall efficiency of the project by lowering the power required for production of oxygen.
- Integration of the Gasification Facility with the Heat Recovery Steam Generator to optimize both efficiency and operating costs.
- The Carbonyl Sulfide Hydrolysis system, which allows such a high percentage of sulfur removal.
- The Slag Fines Recycle system, which recovers carbon remaining in the slag by-product stream and recycles it back for enhanced carbon conversion. This also results in a higher quality by-product slag.
- Fuel Gas Moisturization, which uses low-level heat to reduce steam injection required for NO_x control.
- Sour water treatment and Tail Gas Recycling, which allow more complete recycling of combustible elements, thereby increasing efficiency and reducing waste water and emissions.

System improvements to the Cinergy/PSI facility include:

- Advanced Gas Turbine design to allow for the combustion of syngas and higher firing temperature configurations.
- Complete soft control site utilizing Westinghouse WDPF distributed control system and GE Mark V controls.
- Utilization of saturated steam produced in the HRU of the gasification facility.
- An on-site simulator for use in operator and maintenance training sponsored by EPRI.

- Optical pyrometry installed on the gas turbine to monitor real time blade temperatures.
- Plant monitoring is accomplished through the use of Oil Systems PI software.
- The employees for Cinergy/PSI were hired and do function with the flexible worker concept, in that there is only one job classification on site. All employees have been trained to work multiple disciplines.
- The project's superior energy efficiency is also attributable to the power generation facilities included in the project. These facilities incorporate the latest advancements in combined-cycle system design while accommodating design constraints necessary to repower the steam turbine, including:
- Repowering of the Existing Steam Turbine involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle is utilized.

V. OPERATIONS EXPERIENCE

The project completed the Commissioning phase in August of 1995 and began the start-up process. By late August, the gasifier was ready for coal feed. The project was in the start-up and testing mode through mid November at which time the start-up tests were complete and the project was ready for the Commercial Operation and Demonstration phase to begin. Significant in the start-up phase was the successful demonstration of the thermal integration of the combined operations. There were no substantial problems integrating the steam and water systems, although some early feed-water control problems contributed to early operation interruptions that carried over to the commercial operating period. These problems were resolved early in the first commercial operating year. The startup phase also demonstrated product (syngas) and sulfur by-product quality and environmental performance.

Operations Statistics

Gasification Plant Production Statistics

	1996 Commercial Year	1997 Commercial Year	1998* Commercial Year
Gasifier Hours on Coal	1615	4000	1991
Syngas Produced [MMBtu (Dry)]	2,307,494	6,343,923	3,337,334
Coal Processed [Tons]	154,233	401,650	217,433
Longest Continuous Coal Run [Hrs]	253	362	479
Longest Consecutive Day Campaign	19 Days	46 Days	50 Days (continuing)

* Data through 4/19/98

Combined Cycle Plant Production Statistics

	1996 Calendar Year	1997 Calendar Year	1998✧ Calendar Year
Total Combustion Turbine Hrs	2177	4261	1636
Total Combustion Turbine Hrs on Syngas	1553	3701	1497
MWH'S Produced on Syngas	278,164	940,365	425074
Highest Capacity Demonstrated	296MW	296MW	296MW

	Gross	Gross	Gross
Longest Continuous Syngas Operation	151 hours	362 hours	476 hours

✧ Statistics through 04/12/98

TABLE I

The early first commercial year operation of the WRCGRP saw the plant build on the success of the start-up period, with primary focus on attaining maximum sustained capacity for the purpose of final performance testing for the ASU Facility and Gasification Plant. The ASU Performance Testing was completed in February of 1996 during an operating campaign that lasted over 300 hours. In March of 1996, just four months into the operating period, the gasification plant demonstrated extended operation at 100% rated capacity by running over 100 hours at maximum gasifier capacity. During these February and March operating campaigns, the combustion turbine ran smoothly on syngas and had periods of operation at the 192 MW maximum rated capacity on syngas.

As the project accumulated the early run time, evaluation of the technical advances that are a part of this demonstration facility showed that most of the new unit operations performed very well. However, two of the areas contributed problems that affected run time. Both Destec and PSI critically analyze each hour of facility downtime and attributable cause of that downtime. Such an analysis provides early indication of process improvements required. Two critical problem areas were identified early in the first commercial operating year.

The first problem area was the reliability of the particulate removal system, primarily due to breakage of ceramic candle filters in the primary particulate removal vessels. The second problem area was chloride concentrations in both the COS hydrolysis catalyst beds and downstream heat exchangers in the syngas cooler line-up. Unexpected localized high chloride concentrations contributed to catalyst poisoning and chloride stress corrosion cracking in the syngas heat exchangers. Within the gasification plant, a large scale capital improvement project was launched early in the first commercial year to reduce downtime related to these two severe problems as well as address other, less severe process-related problems. An aggressive implementation schedule targeted these improvements for late in the first commercial year in order to maximize impact on second commercial year operating rate. A discussion of these improvements and their positive impact on second commercial year operations follows in the area operations summaries below.

In November of 1997, a petroleum coke test was performed at the site to demonstrate the fuel flexibility of Destec's Gasification Technology. During the test, over 18,000 tons of petroleum coke were gasified to produce 350,000 MMBtu of synthetic gas that was fed to the combustion turbine. No process modifications were made to accommodate the change in feedstock and no negative effects were realized from processing the petroleum coke.

On the power block side the new advanced gas turbine has performed very well on syngas. The turbine's operation has been more stable on syngas than on oil. The blade temperatures have been more evenly distributed and have had less temperature spiking. NO_x is reduced with steam injection and has been adjusted to meet air permit requirements. The turbine experienced three areas of additional work after the acceptance of syngas. The first was in the syngas module and the piping from the module to the gas turbine. Expansion bellows required redesign and replacement to eliminate cracking in the flow sleeves. This problem was corrected by GE efforts in early syngas runs. The second problem is the syngas purge control. These problems were primarily related to field devices such as solenoid valves and flow measuring devices. The solenoids have been redesigned and replaced and GE continues to work on flow measuring devices. The third area was the GE required 2-3 spacer modifications.

The second year of commercial operation identified cracking problems with the combustion turbine combustion liners. Several outages resulted to allow weld repair of cracked liners. The cracking was located near the head end of the liner and around cooling holes. Evaluation of cause resulted in a replacement of the fuel nozzles and liners as a warranty item for GE. Current plans include the first gas turbine combustion inspection in late May of this year.

Also in the second year of operation tube leaks in the HRSG superheater and reheater area became a degrader of availability. The cause of the tube leaks has been determined to be limiting of needed expansion during startup conditions. A change to the main steam piping support system was made. In February, a change was made in the boiler roof/penthouse floor to allow for better expansion of the roof panels to reduce the stress created on the vertical tubing that results from the binding roof panels. Since those repairs, inspections have found no tube leaks and operation checks for makeup indicate boiler water makeup is normal.

The following is an operations summary of each major operating area, including the areas mentioned above, with a discussion of the process modifications incorporated to address the early problems encountered and the impact of these modifications.

Area Operations Summaries

Coal Slurry Preparation. Coal is ground into a slurry in a rodmill, using recycled water from the gasification process. Wet milling reduces potential fugitive particulate emissions and minimizes water consumption and effluent waste water volume. The slurry is stored in an agitated tank large enough to supply the gasifier needs during forced rodmill outages.

The slurry preparation area has processed over 750,000 tons of coal with no significant problems. The slurry storage and feed systems have also performed very well since the beginning. In fact, only a few hours of downtime since start-up can be directly attributed to these two systems. Typical coal properties have remained consistent during the first two years of operation and are as indicated in Table II below.

COAL PROPERTIES	
Moisture	5-15%
Ash	5-15%
Sulfur (dry)	2.3 - 5.9%
Ash fusion temperature	2000-2500°F
Heating Value	Over 13,500 Btu/lb (HHV)

TABLE II

Oxygen/Nitrogen Generation and Supply. The Air Separation Unit, supplied by Liquid Air Engineering Co. (LAEC), produces 2060 t/d oxygen at 95% purity as well as high-purity nitrogen and dry process air for use in the gasification process. The process involves air compression, purification, cryogenic distillation, oxygen compression, and a nitrogen storage and handling system. Modifications to the plant were necessary after initial performance testing due to the plants' inability to produce the required quantity of products on a continuous basis. Namely, the nitrogen production fell short and early operation of the plant involved supplemental nitrogen supply via trucks. After modifications, the ASU has reliably supplied products to the gasifier island.

Gasification and Slag Handling. The two-stage Destec gasifier operates with a slagging first stage and an entrained-flow second stage. Coal slurry and oxygen are fed to the first stage as well as recycled char from the particulate removal system. This stage operates at 2600°F, producing syngas, which exits to the second stage. Molten slag exits the first stage through a taphole and is quenched in a quench bath prior to removal through Destec's continuous slag removal system. The second stage of the gasifier uses additional slurry to lower the temperature to 1900°F. Raw syngas exits the gasifier enroute to the syngas cooler.

The gasification and slag handling areas have continued to perform well. The slag removal system has continued to operate essentially trouble free in the second commercial operating year. The gasifier has consistently processed the coal into high-quality syngas. The taphole from which the slag by-product is removed from the gasifier has plugged on two occasions, but in neither case was this incident directly related to gasifier performance. In February of 1997, an ill-timed boiler feed-water outage prevented hot gasifier operation on methane after a transfer off of coal. The 10-hour outage resulted in a frozen taphole. Later in the year, an excessive quantity of foreign material in the coal feed to the plant reduced rod mill efficiency and resulted in a large quantity of oversized coal, limestone and other material in the product. The net result, Destec believes, was a slurry feed fluctuation problem to the gasifier that resulted in the taphole plug. Both of these incidents required mechanical slag removal from the gasifier and an associated 10-12 days of downtime. Although high pressure slurry burners have required replacement approximately every 1000 hours, the availability impact has been insignificant since burners can be changed in less than 18 hours coal-to-coal.

Syngas Cooling, Particulate Removal, and COS Hydrolysis. Syngas containing entrained particulates and sulfur exits the gasifier and is cooled in a firetube heat recovery boiler system, producing 1600 psig saturated steam. Raw gas leaving the boiler passes through a barrier filter unit to remove particulates (char) for recycle to the first stage of the gasifier. The particulate free gas is further cooled prior to entering the carbonyl sulfide (COS) hydrolysis unit where COS in the raw gas is converted to hydrogen sulfide (H_2S) for efficient removal in the Acid Gas Removal system. During the first commercial operating year, this area of the gasification plant experienced problems which can be summarized into three areas: (1) ash deposition at the inlet to the firetube boiler, (2) particulate breakthrough in the barrier filter system, and (3) poisoning of the COS catalyst due to chlorides and metals in the syngas. It was these problems that necessitated a large-scale capital improvement program initiated early in 1996.

Ash deposition has not been a major contributor to overall downtime, but has limited run time on several occasions during the second commercial year due to deposition at the inlet to the waste heat boiler tubes. A major improvement was implemented in the third quarter of 1997. This improvement modifies hot gas path flow geometry and velocities so as to minimize large-scale deposits, which can spall off to produce deposition within the waste heat boiler. Management of the ash that does reach the boiler has been improved such that the boiler now remains clean for extended run lengths.

Particulate breakthrough within the barrier filter system experienced during the first commercial year was primarily due to movement and breakage of the ceramic candle filter elements. Substantial downtime is associated with entry into the particulate filter vessels. Therefore, the improvement projects identified early in 1996 placed significant emphasis on improvements to this system to eliminate particulate breakthrough. These improvements were implemented during the fourth quarter of 1996 and have proven successful. Downtime associated with the barrier filtration system has been reduced by nearly 80% over the first commercial year statistics. The single gasification plant outage during the second commercial year resulting from candle element failure was directly related to a failure within the pulse valve system. Consequently, the barrier filtration system has accounted for less than 16 days of outage time due to candle element problems in 1997 vs well over 100 days in 1996. Most of the barrier filtration downtime in 1997 was a result of filter element blinding, which required off-line cleaning. In February of this year new elements, resistant to blinding, were installed that, based on current differential pressure data, will not require cleaning during their service life. As a result, no additional downtime associated with this system is anticipated for 1998.

To further maximize the availability of the particulate removal system and minimize maintenance costs, the plant has installed a slip stream unit capable of testing alternate filter element materials as well as process operating condition effects on element conditioning and overall life. Since commissioning in the fourth quarter of 1997, the unit has successfully logged over 600 coal hours and completed four successful research campaigns.

Poisoning of the COS hydrolysis catalyst due to chlorides and metals led to early replacement of the catalyst. To address this concern as well as metallurgy concerns with chlorides further downstream in the process, a wet chloride scrubber system was installed during September of 1996 as the first phase of process improvements. Since start-up in October of 1996, this system has performed per design in the removal of chlorides from the syngas and has eliminated poisoning concerns within the hydrolysis catalyst as well as corrosion concerns in the downstream equipment. An additional target of the process improvement plan was the identification of an alternate hydrolysis catalyst, less prone to poisoning from both chlorides and trace metals within the syngas. Alternate catalyst was identified and installed in October of 1997 and has proven high performance in the hydrolysis process with minimal degradation in performance over extended run time.

Low Temperature Heat Recovery and Syngas Moisturization. After exiting the chloride scrubbing system and COS hydrolysis unit, low-level heat is removed from the syngas in a series of shell-and-tube heat exchangers prior to acid gas removal. This low level heat is used for syngas moisturization, stripping of the acid gas in the acid gas removal system, and preheating condensate. Since the installation of the new chloride scrubbing system late in the first commercial year, this section of the process has performed well in terms of providing the moisturization for the syngas and providing heat transfer as designed.

Acid Gas Removal and Sulfur Recovery. The acid gas removal system primarily consists of an H_2S absorber column and an H_2S stripper column. H_2S is removed from the syngas in the absorber using a solvent (MDEA) and the syngas is then routed to the moisturizer column mentioned previously. The H_2S removed in the absorber is stripped and routed to the Claus process where it is converted to elemental sulfur. The remaining small amount of unrecovered sulfur in the acid gas is compressed for recycle to the gasifier or sent to the tail gas incinerator, which is one of the permitted air emissions sources. The acid gas removal process has effectively demonstrated removal of over 99% of the sulfur in the syngas, with second commercial year overall sulfur recovery at better than 98%. The typical sweet syngas composition from the plant has been consistent and is shown in Table III. The other permitted air emission sources are the combustion turbine exhaust and the syngas flare.

TYPICAL SYNGAS COMPOSITION	
Component	**Volume Percent**
Hydrogen (H_2)	28
Carbon Monoxide (CO)	38
Carbon Dioxide (CO_2)	10
Methane (CH_4)	1
Nitrogen (N_2)	1
Water (H_2O)	22
Sulfur Compounds	<100 ppmv
Heating Value (dry)	275-280 Btu/scf (HHV)

TABLE III

Environmental Performance. Total sulfur dioxide (SO_2) emissions from the three permitted emissions points (HRSG stack, gasification flare stack, and tail gas incinerator stack) have demonstrated the ability of the gasification process to successfully operate below 0.1 lbs SO_2 emitted per MMBtu of coal input. To date, emission rates as low as 0.03 lbs/MMBtu have been attained. This represents better than a 94% reduction in SO_2 emissions from the decommissioned Unit 1 boiler at the Wabash River Generating Station. The 0.1 lbs/MMBtu is significantly below acid rain limits set for the year 2000 at 1.2 lbs/MMBtu under the Clean Air Act. Through March of 1998, the Project has captured approximately 65 million pounds of sulfur dioxide emissions as 99.99% pure elemental sulfur.

Sour Water Treatment. Sour water is condensed from the syngas in the low-temperature heat-recovery section of the gasification plant. This water is primarily used for recycle to the slurry plant to produce coal slurry. The recycled water is stripped of all dissolved gases except ammonia, which remains in the recycled water. Excess water is stripped of all dissolved gases and discharged through the permitted outfall. The sour water treatment system has performed well.

Combustion Turbine. The combustion turbine has operated in excess of 9200 fired hours on syngas and No 2 fuel oil. The combustion turbine has operated in a short cycle configuration (without the gasification plant) as a liquid-fired combined-cycle peak-service generator. In this mode the combustion turbine is limited to 150MW, due to HRSG steam temperatures. Both peak and baseload operations have proven to be stable and viable options for the operation of the generator on the bulk power system. The combustion turbine control system (Mark V) has proven, after initial startup tuning, to be reliable and maintainable by on-site PSI technicians. This system does require formal GE training for the technicians to develop the necessary skills for long-term maintenance. Technicians were trained to maintain gas turbine controls (Mark V), the excitation system (EX2000) and the gas turbine cranking system, (LCI). On-site control maintenance capability is critical to establishing an available and reliable combined-cycle power block.

Steam Turbine. The steam turbine is an early 1950s vintage Westinghouse reheat turbine. The original nameplate for the steam turbine was 99 MW. The current rating is 104 MW due to the removal of all the steam extractions with the exception of cold reheat. Throttle pressure has been maintained at the original 1,450 psig and throttle temperature is 1,005°F. The steam turbine and turbine auxiliaries are located approximately 1,600 feet from the gas turbine power block and consequently required extensive piping and drain installations. It was decided early in the design phase that steam turbine operator interface would be in the new control room with the new power block controls, Westinghouse WDPF. The condensate and feed-water heating extractions were removed and capped. The cold reheat extraction was inspected and maintained for the repowered operation. One row of blading was replaced in the LP as a result of the repowering. The generator was rewound and the generator rotor was replaced. A new static excitation system was installed to improve the reliability. The hydraulic turbine controls were replaced with the Westinghouse DEH control system. The throttle and governor valve hydraulic system was disconnected and replaced with SCA's (self contained actuators) mounted at each valve control point. This system has preformed very well. Existing TSI's were left in place and remain functional. The turbine experienced an early control shaft failure due to an improperly sized cold reheat orifice causing the rotor to thrust resulting in the failure. Otherwise, the steam turbine has operated very well in the new configuration. It was expected that the limiting factor for load control would be the steam turbine/generator. This has not been the case. With the DEH controls and the SCA's the steam T/G responds as quickly as the gas turbine. Limitations are the ability to control steam temperature during load movement. Although this site is baseloaded the information provided by the experience of retrofitted steam turbine controls using Westinghouse WDPF, DEH and the SCA's recommended by Westinghouse have certainly been a good decision.

Water Treatment. Water treatment was designed to meet the needs of both the power block and the gasification island. Surface water is drawn from the Wabash River, clarified with a CBI Claricone, filtered and flowed to various demands on both operating blocks in the project. The filtered water is then treated for influent in the two parallel 480-gpm LA Hipol demineralizers. There is 750,000 gallons of demineralized water storage capability. This water is the supply for the steam cycles of the power block and the gasification island. The control of the water facility is also included in the scope of the Westinghouse WDPF system and can be operated from the central control room. Operation of the water facility has been reliable and cost effective.

VI. OUTLOOK/SUMMARY

During the third commercial year of operation, the Wabash River Coal Gasification Repowering Project has continued to make progress towards achieving the project goals. Both the gasification and combined-cycle plants have demonstrated the ability to run at capacity and within environmental compliance while using locally mined coal. Early identification of availability limiting process problems within the gasification plant led to aggressive implementation of improvement projects which has resulted in 275% more syngas produced during the second commercial operating year. Based on current production through April 20, 1998, the third commercial year is on track to exceed the second year's production by an additional 37%. Further analysis of downtime contributors and subsequent modifications, as well as indicated slipstream testing will improve plant operation and allow complete demonstration of the project goals.

Cinergy/PSI is very interested in the continued improvement of the site and in improving it's fuel flexibility in terms of accepting multiple coal feedstocks. We are currently single sourced and are looking forward to a multiple supplier arrangement to help ensure the long-term success.

With improved operation, the project looks forward to continued demonstration of the viability of the technology. Consideration is being given for alternate fuel testing along with continued emphasis in improvement of operating rate and costs.

COMMERCIAL-SCALE DEMONSTRATION OF THE LIQUID PHASE METHANOL (LPMEOH™) PROCESS: INITIAL OPERATING EXPERIENCE

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ABSTRACT

The Liquid Phase Methanol (LPMEOH™) process uses a slurry bubble column reactor to convert synthesis gas (syngas), primarily a mixture of carbon monoxide and hydrogen, to methanol. Because of its superior heat management, the process can utilize directly the carbon monoxide (CO)-rich syngas characteristic of the gasification of coal, petroleum coke, residual oil, wastes, or other hydrocarbon feedstocks. When added to an integrated gasification combined cycle (IGCC) power plant, the LPMEOH™ process converts a portion of the CO-rich syngas produced by the gasifier to methanol, and the unconverted gas is used to fuel the gas turbine combined-cycle power plant. In addition, the LPMEOH™ process has the flexibility to operate in a daily load-following pattern, co-producing methanol during periods of low electricity demand, and idling during peak times. Coproduction of power and methanol via IGCC and the LPMEOH™ process provides opportunities for energy storage for electrical demand peak shaving, clean fuel for export, and/or chemical methanol sales.

Construction of the LPMEOH™ Process Demonstration Plant was completed in January of 1997 at Eastman Chemical Company's chemicals-from-coal complex in Kingsport, Tennessee. Following commissioning and shakedown activities, the first production of methanol from the 260 tons-per-day (TPD) plant occurred on April 2, 1997. Nameplate capacity was reached for

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the first time on April 6, 1997, and production rates of over 300 TPD of methanol have been achieved. Since startup, availability for the LPMEOH™ Demonstration plant has exceeded 92%.

This paper provides a description of the LPMEOH™ process, the commercial applications for the technology, and a review of the startup and plant performance results at the Kingsport site.

I. INTRODUCTION

The LPMEOH™ technology was developed during the 1980's with the financial support of the U. S. Department of Energy (DOE). The concept was proven in over 7,400 hours of test operation in a DOE-owned, 10 tons-per-day (TPD) Process Development Unit (PDU) located at LaPorte, Texas.[1] The first commercial-scale demonstration plant for the technology was sited at Eastman Chemical Company's (Eastman's) coal gasification facility in Kingsport, Tennessee, with the help of a $92.7 million award under the DOE's Clean Coal Technology Program. Construction began in October of 1995 and concluded in January of 1997. After commissioning and startup activities were completed, operation began in April of 1997. During a four-year operating program, the LPMEOH™ Process Demonstration Plant will demonstrate the production of at least 260 TPD of methanol, and will simulate operation for the integrated gasification combined cycle (IGCC) coproduction of power and methanol application. The test plan will also seek to establish commercial acceptance of the technology and verify the fitness of the methanol product through a series of off-site, product-use tests. Total cost of the project, including the four-year demonstration test program, is forecast at $213.7 million.

Air Products and Chemicals, Inc. (Air Products) and Eastman formed the "Air Products Liquid Phase Conversion Co., L.P." partnership to execute the project and own the LPMEOH™ Demonstration Plant. Air Products manages the overall project and provides technology analysis and direction for the demonstration. Air Products also provided the design, procurement, and construction of the plant (i.e., a turnkey facility). Eastman provides the host site, acquired the necessary permits, operates the demonstration plant, supplies the supporting auxiliaries and the synthesis gas (syngas), and takes the product methanol. Most of the product methanol is refined to chemical-grade quality (99.85 wt% purity) via distillation and used by Eastman as chemical feedstock elsewhere in their commercial facility. A portion of the product methanol will be withdrawn prior to purification (about 98 wt% purity) for use in off-site, product-use tests.

This paper reviews: The **Commercial Application** for the LPMEOH™ process technology; the **Demonstration Plant - Test Plans**, highlighting the operational plans to confirm the commercial application; and, the **Demonstration Plant - Current Performance Results**, highlighting the operating results achieved to date.

II. COMMERCIAL APPLICATION

Technology Description

The heart of the LPMEOH™ process is the slurry bubble column reactor (Figure 1).

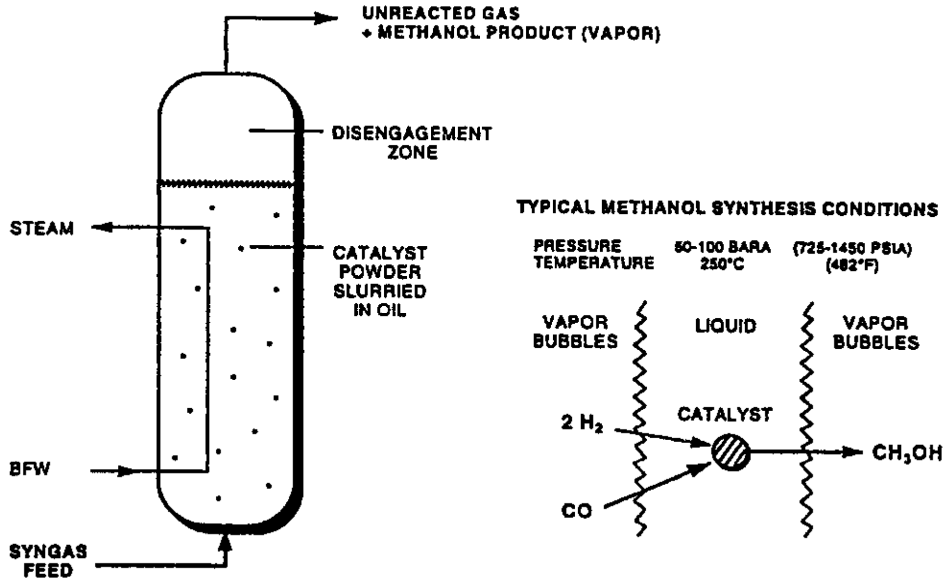

Figure 1. LPMEOH™ Reactor and Reaction Schematics

Conventional methanol reactors use fixed beds of catalyst pellets and operate in the gas phase. The LPMEOH™ reactor uses catalyst in powder form, slurried in an inert mineral oil. The mineral oil acts as a temperature moderator and a heat removal medium, transferring the heat of reaction from the catalyst surface via the liquid slurry to boiling water in an internal tubular heat exchanger. Since the heat transfer coefficient on the slurry side of the exchanger is relatively large, the heat exchanger occupies only a small fraction of the cross-sectional area of the reactor. As a result of this capability to remove heat and maintain a constant, highly uniform temperature through the entire length of the reactor, the slurry reactor can achieve much higher syngas conversion per pass than its gas-phase counterparts.

Furthermore, because of the LPMEOH™ reactor's unique temperature control capabilities, it can *directly* process syngas that is rich in carbon oxides (carbon monoxide and carbon dioxide). Gas-phase methanol technology would require that similar feedstocks undergo stoichiometry adjustment by the water gas shift reaction, to increase the hydrogen content and subsequent carbon dioxide (CO_2) removal. In a gas-phase reactor, temperature moderation is achieved by recycling large quantities of hydrogen (H_2)-rich gas, utilizing the higher heat capacity of H_2, as compared to carbon monoxide (CO). Typically, a gas-phase process is limited to about 16% CO in the reactor inlet, as a means of constraining the conversion per pass to avoid excess heating. In contrast, for the LPMEOH™ reactor, CO concentrations in excess of 50% have been tested routinely in the laboratory and at the PDU in LaPorte, without any adverse effect on catalyst activity.

A second distinctive feature of the LPMEOH™ reactor is its robust character. The slurry reactor is suitable for rapid ramping, idling, and even extreme stop/start actions. The thermal moderation provided by the liquid inventory in the reactor acts to buffer sharp transient operations that would not normally be tolerable in a gas-phase methanol synthesis reactor. This characteristic is especially advantageous in the environment of electricity demand load-following in IGCC facilities.

A third differentiating feature of the LPMEOH™ process is that a high quality methanol product is produced directly from syngas rich in carbon oxides. Gas-phase methanol synthesis, which must rely on H_2-rich syngas, yields a crude methanol product with 4% to 20% water by weight. The product from the LPMEOH™ process, using CO-rich syngas, typically contains only 1% water by weight. As a result, raw methanol coproduced in an IGCC facility would be suitable for many applications at a substantial savings in purification costs. The steam generated in the LPMEOH™ reactor is suitable for purification of the methanol product to a higher quality or for use in the IGCC power generation cycle.

Another unique feature of the LPMEOH™ process is the ability to withdraw spent catalyst slurry and add fresh catalyst on-line periodically. This facilitates uninterrupted operation and also allows perpetuation of high productivity in the reactor. Furthermore, choice of replacement rate permits optimization of reactor productivity versus catalyst replacement cost.

IGCC Coproduction Options

The LPMEOH™ process is a very effective technology for converting a portion of an IGCC electric power plant's coal-derived syngas to methanol[2], as depicted in Figure 2. The process has the flexibility to handle wide variations in syngas composition. It can be designed to operate in a continuous, baseload manner, converting syngas from oversized gasifiers or from a spare gasifier. Alternatively, the process can be designed to operate only during periods of off-peak electric power demand, consuming a portion of the excess syngas and reducing the electricity output from the combined-cycle power unit. In this scenario, the gasification unit continues to operate at full baseload capacity, so that the IGCC facility's major capital asset is always fully utilized.

In either baseload or cycling operation, partial conversion of between 20% and 33% of the IGCC plant's syngas is optimal, and conversion of up to 50% is feasible. The required degree of conversion of syngas, or the quantity of methanol relative to the power plant size, determines the design configuration for the LPMEOH™ plant. In its simplest configuration, syngas at maximum available pressure from the IGCC electric power plant passes once-through the LPMEOH™ plant and is partially converted to methanol without recycle, water-gas shift, or CO_2 removal. The unreacted gas is returned to the IGCC power plant's combustion turbines. If greater syngas conversion is required, different plant design options are available.[3]

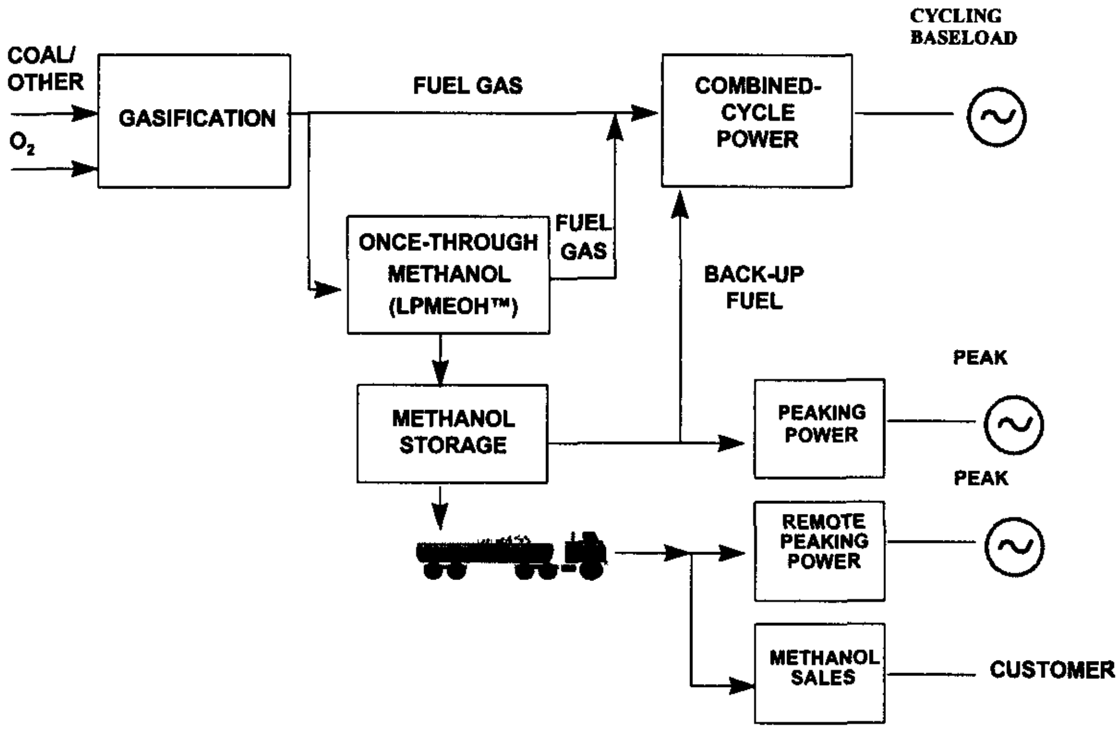

Figure 2.
Once-through Methanol Coproduction with IGCC Electric Power

Economics for Baseload Coproduction of Methanol and Power

Design studies for the LPMEOH™ process have focused principally on the aforementioned IGCC applications. For a given gasification plant size, the IGCC coproduction plant can be designed to accommodate a range of methanol to power output ratio's. For example,[4, 5] a gasification plant, with two gasifiers of 1735 million Btu (HHV) per hour output each, could be sized for baseload power output of 426 megawatts of electricity (MWe) and for baseload methanol coproduction of 500 TPD. If the baseload fuel gas value is $4.00 per million Btu, then 500 TPD of methanol can be coproduced from coal for under 50 cents per gallon.[3] This compares with new methanol plants which, using natural gas at $0.50 to $1.00 per million Btu as feedstock and the same basis for capital recovery, produce chemical-grade methanol delivered to the U. S. Gulf Coast at 55 to 60 cents per gallon.[6, 7] Methanol coproduction, by IGCC and the once-through LPMEOH™ process, does not require large methanol plant sizes to achieve good economies of scale. The gasification plant is necessarily at a large economical scale for power generation, so the syngas manufacturing economies are already achieved. Methanol storage and transport economies are also achieved by serving local markets, and realizing freight savings over competing methanol, which is usually shipped from the U. S. Gulf coast.

The 50 cents per gallon coproduction cost for a 500 TPD once-through LPMEOH™ plant size is competitive in local markets with new world-scale offshore methanol plants. An additional 3 to

4 cents per gallon savings is attainable for a 1200 TPD LPMEOH™ plant size.[3] These additional savings might be used to offset higher freight costs to more distant customers, while still maintaining a freight and cost advantage over imported methanol from the Gulf Coast.

III. DEMONSTRATION PLANT - TEST PLANS

The preceding Commercial Application section highlighted the advantages of the LPMEOH™ process as part of an IGCC electric power generation system. To confirm these commercial advantages during operations, the demonstration test plan incorporates, but is not limited to, the following commercially important aspects of IGCC integration:

- **Syngas compositions will vary** with the type of gasification process technology and feedstock used in the power generation application. Therefore, operation over a wide variety of syngas compositions will be demonstrated.
- **Catalyst life,** operating on coal-derived syngas, must be demonstrated over a long period of time. Major parameters include reactor operating temperature, concentration of poisons in the reactor feed gas, and catalyst aging and attrition.
- **Reactor volumetric productivity** must be optimized for future commercial designs. Parameters include: High inlet superficial velocity of feed gas, high slurry catalyst concentration, maximum gassed slurry level, and removal of the heat of reaction.
- **Methanol Product,** as produced by the LPMEOH™ reactor from syngas rich in carbon oxides, must be suitable for its intended uses. Off-site methanol product-use testing will confirm the product specifications needed for market acceptability.

Although generation of electric power is not a feature of the demonstration project at Kingsport, the demonstration test plan is structured to provide valuable data related to the following:

- **coproduction** of electric power and value-added liquid transportation fuels and/or chemical feedstocks from coal. This coproduction requires that the partial conversion of syngas to storable liquid products be demonstrated.
- **energy load-following** operations that allow conversion of off-peak energy, at attendant low value, into peak energy commanding a higher value. This load-following concept requires that on/off and syngas load-following capabilities be demonstrated.

Three key results will be used to judge the success of the LPMEOH™ process demonstration during the four years of operational testing:

- resolution of technical issues involved with scaleup and first time demonstration for various commercial-scale operations;
- acquisition of sufficient engineering data for future commercial designs; and,
- industry or commercial acceptance.

The demonstration test plan provides flexibility to help meet these success criteria. Annual operating plans, with specific targeted test runs, will be prepared, and revised as necessary. These plans will be tailored to reflect past performance, as well as commercial needs.

The LPMEOH™ operating test plan outline, by year, is summarized in Table 1. The demonstration test plan encompasses the range of conditions and operating circumstances anticipated for methanol coproduction with electric power in an IGCC power plant. Since Kingsport does not have a combined-cycle power generation unit, the tests will simulate the IGCC application. In addition, the test program will emphasize test duration. The minimum duration for a test condition, apart from the rapid ramping tests, is 2 weeks. Numerous tests will have 3 to 6 week run periods, some 8 to 12 weeks, and a few key basic tests of 20 to 30 weeks.

The ultimate goal of the demonstration period is to reach a stable, optimized operating condition, with the best combination of the most aggressive operating parameters. These parameters, such as reactor superficial gas velocity, slurry concentration, and reactor level, will allow maximum reactor productivity to be achieved. Debottlenecking limitations of the demonstration plant will be an ongoing goal during the demonstration period.

Table 1.
LPMEOH™ Demonstration Test Plan Outline

Year 1	Catalyst Aging
	    Catalyst Life vs. LaPorte process development unit and Lab Autoclaves
	Process Optimization / Maximum Reactor Productivity
	    Catalyst Slurry Concentration (increasing to 40 wt%)
	    Reactor Slurry Level
	    Catalyst Slurry Addition Frequency Test
	    Gas Superficial Velocity
	Establishment of Baseline Condition

Years 2 & 3	Catalyst Slurry Addition and Withdrawal at Baseline Condition
	Catalyst Attrition/Poisons/Activity/Aging Tests
	Simulation of IGCC Coproduction for:
	  1. Syngas Composition Studies for Commercial Gasifiers
	      Texaco, Shell, Destec, British Gas/Lurgi, Other Gasifiers
	  2. IGCC Electrical Demand Load Following:
	      Rapid Ramping, Stop/Start (Hot and Cold Standby).
	  3. Additional Industry User Tests
	Maximum Catalyst Slurry Concentration (exceeding 40 wt%)
	Maximum Throughput/Production Rate

Year 4	Stable, extended Operation at Optimum Conditions 99% Availability Potential Alternative Catalyst Test Additional Industry User Tests

IV. DEMONSTRATION PLANT - CURRENT PERFORMANCE RESULTS

Kingsport Site

Eastman began coal gasification operations at Kingsport, TN in 1983. Texaco gasification converts about 1,000 tons-per-day of high-sulfur, Eastern bituminous coal to syngas for the manufacture of methanol, acetic anhydride, and associated products. Air Products provides the oxygen for gasification by a pipeline from an over-the-fence air separation unit. The crude syngas is quenched, partially shifted, treated for acid gas removal (hydrogen sulfide, carbonyl sulfide, and CO_2) via Rectisol, and partially processed in a cryogenic separation unit to produce separate H_2 and CO streams. The H_2 stream is combined with clean syngas to produce stoichiometrically balanced feed for a conventional gas-phase methanol synthesis unit, which is further polished in an arsine- and sulfur-removal guard bed. The methanol product reacts with recovered acetic acid to produce methyl acetate. Finally, the methyl acetate reacts with the pure CO stream to produce the prime product, acetic anhydride (and acetic acid for recycle).

Because the gasification facility produces individual streams of clean balanced syngas (Balanced Gas), CO (CO Gas), and H_2-rich gas (H_2 Gas), the LPMEOH™ Demonstration Plant design includes the capability to blend these streams into a wide range of syngas compositions. This flexibility enables the plant to simulate the feed gas composition available from any commercial gasifier.

Process Description

Figure 3 shows a simplified process flow diagram of the LPMEOH™ Demonstration Plant. Approximately half of the Balanced Gas fresh feed to the existing methanol unit is diverted to the LPMEOH™ Demonstration Plant, where it combines with the high-purity CO Gas and passes through an activated carbon guard bed. This bed removes iron and nickel carbonyls, which are poisons to methanol synthesis catalyst, down to ppb levels. The third feed stream, H_2 Gas, is the hydrogen-rich purge exiting the existing methanol unit. Since the H_2 Gas is at lower pressure than the other two feed streams, it is combined with the Recycle Gas stream, made up of unconverted syngas from the LPMEOH™ reactor, and compressed in the recycle compressor.

These two pairs of streams are then combined to form a single high pressure reactor feed gas stream that is preheated in the feed/product economizer against the reactor effluent. The feed gas is then sparged into the LPMEOH™ reactor, where it mixes with the catalyst slurry and is partially converted to methanol vapor, releasing the heat of reaction to the slurry. The slurry temperature is controlled by varying the steam temperature within the heat exchanger tubes, which is accomplished by adjusting the steam pressure.

Disengagement of the effluent gas (methanol vapor and unreacted syngas) from the catalyst/oil slurry occurs in the freeboard region of the reactor. Any entrained slurry droplets leaving the top of the reactor are collected in the cyclone separator. The product gas passes through the tubeside of the feed/product economizer, where it is cooled against the reactor inlet gas stream. Any condensed oil droplets are collected in the high-pressure oil separator and then returned to the reactor with the entrained slurry from the cyclone separator.

The product gas is cooled further in a series of air-cooled and cooling water exchangers, whereupon the product methanol condenses and collects in the high pressure methanol separator. Most of the unreacted syngas returns to the reactor after undergoing compression in the recycle compressor. The balance of the unreacted syngas is purged to the Eastman fuel gas system.

The condensed methanol contains dissolved gases, water, trace oil, and some higher alcohols. These impurities are removed in a two-column distillation train that produces a methyl acetate feed-grade methanol product. The bottom draw from the second column is a crude methanol stream heavy in higher alcohols, water, and any oil carried over from the reactor. This stream is sent to the existing distillation system for recovery of the methanol and disposal of the byproducts. Stabilized, fuel-grade methanol for off-site product-use testing will be produced at limited times during the demonstration period by using only the first distillation column.

Catalyst slurry is activated in the catalyst reduction vessel, which is equipped with a heating/cooling jacket, utility oil skid, and agitator. Pure CO, diluted in nitrogen, acts as the reducing agent. During the activation procedure, slurry temperature is carefully increased while monitoring consumption of CO to determine when the catalyst is completely reduced. At the end of this procedure, the catalyst is fully active and can be pumped directly to the reactor. As fresh catalyst slurry is added to the LPMEOH™ reactor, catalyst inventory is maintained by withdrawing an equivalent amount of partially deactivated or spent slurry.

Initial Operation

Table 2 summarizes the commissioning and startup milestones at the LPMEOH™ Demonstration Plant.

Table 2.

LPMEOH™ Demonstration Plant Milestones

• Groundbreaking	October 1995
• Plant Mechanically Complete	January 1997
• Eastman Begins Commissioning	February 1997
• Completed Startup	April 1997
• Syngas In	April 2, 1997
• Design Production of 260 TPD MeOH	April 6, 1997
• Greater Than 300 TPD MeOH	April 10, 1997
• Availability Since Startup	92%

In addition, a transportable laboratory was shipped to Kingsport in May of 1996 to test the long-term performance of a continuous stirred-tank autoclave on the coal-derived syngas at the Eastman complex. Over the past 20 years, Air Products has developed the skills and analytical techniques to sample syngas streams and detect concentrations of specific components at the parts-per-billion level. These tests indicated no unusually high levels of known catalyst poisons, and the autoclave produced a typical laboratory catalyst activity curve over a 28-day campaign.

Figure 4 shows performance results from the LPMEOH™ reactor during the first several months of operation. The data are reduced to a ratio of rate constant pre-exponential factors (actual vs. design value for fresh catalyst), using an in-house kinetic model, to eliminate the effects of changing feed composition or operating conditions. Typical exponential decay will appear as a straight line on a log-plot, as shown. The curve fit to data from a 4-month test at the LaPorte PDU in 1988/89 is included for reference. The plant results from the initial start-up in April of 1997 showed excellent initial activity, verifying the activation procedure for the catalyst. During the first month of operation, however, an accelerated change in performance occurred; whereas, the remaining operation from June through November matched the typical activity loss measured in the laboratory. This included the performance during the ongoing addition of fresh catalyst batches to the reactor to build inventory and maintain a viable overall level of activity. In fact, the eventual replacement rate of spent catalyst should maintain the average activity in the reactor at about half the fresh value, although that choice is ultimately an economic optimization of catalyst usage rate vs. reactor productivity. Notably, operations at the LaPorte PDU used natural gas feedstock for the generation of the CO-rich syngas fed to the reactor. In this "clean" environment, the methanol catalyst exhibited a very slow loss of activity with time.

An important feature of the LPMEOH™ process is the ability to remove spent catalyst from the reactor during operation; this also affords the opportunity to examine samples for changes in the microscopic structure and/or chemical make-up of the catalyst with time. Analyses of such samples from Kingsport have indicated a step-change in the concentration of iron on the catalyst surface during the initial six weeks, which cannot be correlated to the presence of iron carbonyl in the feed gas streams. This finding may be related to the detection of post-construction debris within various parts of the facility, or an incipient production of iron carbonyl within the new piping systems, characteristic of a passivation-like mechanism which decreased rapidly with time. Higher than expected levels of arsenic were also found on the catalyst samples. However, a subsequent changeout of Eastman's arsine-removal guard bed, and laboratory tests using arsine-doped syngas, failed to prove that arsine alone was responsible for the catalyst deactivation in the plant. Regardless, the plant originally came on-stream with less than a full charge of catalyst to mitigate the risk of exposure to anomalous contaminants during the initial start-up.

Based on these results, the reactor was drained and another partial charge of fresh catalyst was activated during December of 1997. The calculated catalyst activity curve since the restart is included in Figure 5, along with additional data from the transportable laboratory operating in parallel on the same reactor feed gas. The initial catalyst performance has been excellent, with methanol production again exceeding nameplate capacity and plant availability exceeding 99.9%

through the first six weeks. Also, a rapid decrease in activity did not occur during the initial month on-stream, as compared to the results from April of 1997. Furthermore, the activity maintenance in the LPMEOH™ reactor appears to exceed the results from the parallel laboratory run. However, while the initial activity is higher than the 1988/89 results from the LaPorte PDU, the decrease with time remains measurably greater. This disparity is thought to be caused by the presence of trace levels of catalyst poisons (iron, sulfur, arsenic, etc.) in syngas generated from coal.

Operation with CO-rich Syngas

Two test runs using a CO-rich feed gas to the LPMEOH™ reactor have been completed. The H_2/CO ratio of the reactor feed for these cases varied between 0.4 and 0.8. Methanol production matched the predicted quantity for the reactor operating conditions, and the catalyst deactivation rate under CO-rich syngas was equivalent to the H_2-rich rates before and after. The crude methanol composition from a test simulating feed from a Texaco coal gasifier (H_2/CO ratio = 0.8) is shown in Table 3. This methanol has levels of higher alcohols and water similar to as-produced methanol from the LaPorte PDU, which is important because the PDU methanol has already been used successfully in several fuel and chemical applications.

Table 3. Crude Methanol Composition from Texaco-type Feed Gas

	Kingsport #1 (wt%)	Kingsport #2 (wt%)	PDU (wt%)
Methanol	98.0206	98.1442	97.459
Ethanol	0.2999	0.3116	0.593
2-Propanol	0.0328	0.0285	*
1-Propanol	0.0962	0.1030	0.198
2-Butanol	0.0251	0.0258	0.048
iso-Butanol	0.0107	0.0115	0.003
Methyl Propionate	0.0058	0.0059	*
n-Butanol	0.0496	0.0570	0.093
3-Methyl-2-Butanol	0.0104	0.0112	*
2-Methyl-2-Butanol	0.0094	0.0098	*
Methyl Butyrate	0.0066	0.0067	*
2-Methyl-1-Butanol	0.0122	0.0131	*
1-Pentanol	0.0255	0.0299	0.066
3-Pentanol	0.0067	0.0071	*
2-Pentanol	0.0073	0.0079	0.003
Methyl Formate	0.0000	0.0000	0.368
Methyl Acetate	0.0000	0.0000	0.041
Dimethyl Ether	0.0000	0.0000	0.301
Water	1.3000	1.1400	0.543
Mineral Oil	0.0812	0.0868	0.283

* refers to compounds not detected in sample because of analytical technique; however, compounds are probably present in sample, and have been accounted for as other compounds of similar physical properties.

Future Activities

During 1998, efforts will continue to sample the catalyst from the reactor and monitor plant performance to quantify the long-term catalyst aging characteristics under coal-derived syngas. In addition, the slurry concentration in the reactor will be increased to determine the maximum volumetric productivity of methanol. Additional operations with CO-rich syngas and other reactor feed gas compositions are planned.

V. CONCLUSION

The LPMEOH™ process is now being demonstrated at commercial scale under the DOE Clean Coal Technology Program. The demonstration plant, located at Eastman Chemical Company's Kingsport, Tennessee coal gasification facility, has produced in excess of the 260 TPD of methanol nameplate capacity from coal-derived syngas. Since startup of the unit in April of 1997, overall availability has exceeded 92%, while the more recent campaign in 1998 has achieved greater than 99% availability. The startup and initial operation proceeded without injury or environmental incidents, and Eastman has accepted all methanol produced at the LPMEOH™ Demonstration Plant for use in downstream chemical processes.

Successful demonstration of the LPMEOH™ technology will add significant flexibility and dispatch benefits to IGCC electric power plants, which traditionally have been viewed as strictly a baseload power generation technology. Now, central clean coal technology processing plants, making coproducts of electricity and methanol, can meet the needs of local communities for dispersed power and transportation fuel. The LPMEOH™ process provides competitive methanol economics at small methanol plant sizes, and a freight and cost advantage in local markets vis-à-vis large offshore remote gas methanol. Methanol coproduction studies show that methanol can be produced at less than 50 cents per gallon from an abundant, non-inflationary local fuel source, such as coal. The coproduced methanol may be an economical hydrogen source for small fuel cells, and an environmentally advantaged fuel for dispersed electric power.

VI. ACKNOWLEDGEMENT

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THE HEALY CLEAN COAL PROJECT

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ABSTRACT

The Healy Clean Coal Project (HCCP), selected by the U.S. Department of Energy (DOE) under Round III of the Clean Coal Technology Program, is in the demonstration phase. The Project is owned and financed by the Alaska Industrial Development and Export Authority (AIDEA), and is co-funded by the U.S. Department of Energy. Construction was completed in November of 1997, with coal-fired testing starting in January of 1998. Demonstration testing and reporting of the results will take place in 1998, followed by commercial operation of the facility. Formal operational test reports will be provided through June 1999, followed by an additional two years of operational data. The emission levels of oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulates from this 50-megawatt plant are expected to be significantly lower than current standards. The project background, a description of the technology to be demonstrated, project status, and the demonstration goals of this project are presented herein.

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I. BACKGROUND

In September of 1988, Congress provided $575 million under Round III of the Clean Coal Technology Program (CCT) to conduct cost-shared projects to demonstrate technologies that are capable of retrofitting or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued in May of 1989, by the DOE, soliciting proposals to demonstrate innovative energy-efficient technologies that were capable of being commercialized in the 1990s, and were capable of (1) achieving significant reductions in the emissions of sulfur dioxide and/or oxides of nitrogen from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, DOE received 48 proposals in August of 1989. After evaluation, 13 projects were selected in December of 1989 as best furthering the goals and objectives of the PON. The projects were located in ten states and represented a variety of technologies.

One of the 13 projects selected for funding was the Healy Clean Coal Project (HCCP) proposed by the Alaska Industrial Development and Export Authority (AIDEA). The project will demonstrate the combined removal of SO_2, NO_x, and particulates from a new 50-megawatt electric coal-fired power plant using both innovative combustion and flue gas cleanup technologies. AIDEA owns the Project, performs under the DOE Cooperative Agreement, administers State funds, obtains financing through the sale of bonds, and manages the Project. The architect/engineer for the Project is Stone & Webster Engineering Corporation (SWEC). Fairbanks utility Golden Valley Electric Association (GVEA) will operate the facility and pay for power generated under terms of a Power Sales Agreement. Usibelli Coal Mine, Inc. (UCM) provides coal under the terms of a Coal Sale Agreement. The technology suppliers are TRW (coal feed system and combustors), and Joy-Niro, now the Babcock & Wilcox Company (fabric filter and SO_2 removal systems).

The TRW slagging combustor technology has been developed over many years. During 1990 and 1991, Healy coal was tested by TRW in a 35-MMBtu/hr slagging combustor system at TRW's Cleveland test facility. The slagging combustor scaling and operation were as predicted, both from analytical and operational viewpoints. However, it was recognized that the storage-type coal feed system, used in the Cleveland facility, was not desirable because of safety concerns associated with the high volatile content of the Usibelli coal.

The next development stage was to design and fabricate a non-storage coal feed system and test fire a full size precombustor. To assist in the design, cold-flow modeling was conducted by TRW. A 130-MMBtu/hr precombustor was then built and tested in 1992 and 1993 on Healy coal at TRW's Capistrano facilities. In parallel with the TRW testing, Niro conducted pilot tests in Sweden on the SDA system. In addition, Foster Wheeler built gas-flow modeling facilities and tested combustor gas flows to assist in the furnace design.

The Project site is in Healy, Alaska, near the Denali National Park and Reserve. Extensive air quality and visibility monitoring and modeling were conducted as part of the Environmental Impact Statement (EIS) and the Prevention of Significant Deterioration (PSD) permit documentation. Air quality models of the GVEA coal-fired existing Unit 1 emissions were verified and calibrated with ambient air quality and visibility monitors. Two years of visibility monitoring information was collected. The demonstration technologies are vital to assure air emission levels consistent with environmental permits and the conditions necessary to protect the pristine air quality of Denali National Park and Reserve.

The demonstration project is adjacent to the existing GVEA 25-MW Healy Unit No. 1 pulverized coal-fired power plant. Unit No. 1 has recently been converted with low-NO_x burners, provided by Foster Wheeler, that are guaranteed to meet .30 lb/MMBtu NO_x emission permit conditions with blended coal. The project will demonstrate the ability of slagging combustors to utilize low-quality coals effectively. It is anticipated that HCCP and Unit No. 1 may burn the same fuel blends, allowing comparison of low-NO_x burners and the TRW combustors regarding NO_x emissions.

II. TECHNOLOGY TO BE DEMONSTRATED

Coal provided by the UCM, adjacent to the Project site, is pulverized and burned at the new facility to generate high-pressure steam. The high-pressure steam is supplied to a steam turbine generator to produce electricity. Emissions of SO_2 and NO_x from the plant will be controlled using TRW's Entrained Combustor system with limestone injection in conjunction with a boiler designed by Foster Wheeler Energy Corporation (FWEC). Further SO_2 and particulate removal will be accomplished using the Activated Recycle Spray Dryer Absorber (SDA) System and Fabric Filter (FF) developed by Joy-Niro. A material flow diagram and overall process flow diagram are provided in Figures 1 and 2 depicting the process.

The TRW Entrained Combustor is designed to operate under fuel-rich conditions, utilizing two-staged combustion to minimize NO_x formation. These conditions are obtained using a precombustor for heating the fuel-rich main combustor for partial combustion, with combustion completion occurring in the boiler. The first and second stages of combustion produce a temperature high enough to generate a slag (molten ash) while reducing the fuel-bound nitrogen to molecular nitrogen (N_2). Typically 80% of the ash is expected to be removed as slag. The third and final stage of combustion in the boiler occurs at a combustion temperature maintained below the temperature that will cause thermal NO_x formation. Figure 3 shows the main combustor components configuration. Subbituminous coals from the adjacent UCM will be the fuel. Table 1 shows coal properties for the Run of Mine (ROM) and Waste coals.

The combustor is also used to reduce SO_2 emissions by the injection of pulverized limestone into the hot gases as they leave the combustor and enter the furnace. This technique converts the limestone into lime (flash calcination), or flash calcined material (FCM), which reacts with the sulfur compounds in the exhaust gas to form calcium sulfate. Captured SO_2 is removed in the combustor and boiler as bottom ash. The flue gas, which contains the remaining sulfur compounds, calcium sulfate, ash, unused sorbent, and other solid particles, leaves the boiler and passes through an SDA and FF for further SO_2 and particulate removal prior to exiting the stack.

Table 1.
Coal Analyses

PROXIMATE ANALYSIS	**PERCENT BY WEIGHT (AS RECEIVED)**	**RUN-OF-MINE**	**WASTE COAL**
Moisture	(%)	26.35	23.87
Ash	(%)	8.20	25.00
Volatile	(%)	34.57	27.00
Fixed Carbon	(%)	30.89	24.13
Total	(%)	100.00	100.00
Higher Heating Value	(Btu/#)	7815.0	6105.0
ULTIMATE ANALYSIS	**PERCENT BY WEIGHT (AS RECEIVED)**		
Percent By Weight	(%)		
Moisture	(%)	26.35	23.87
Carbon	(%)	45.55	35.59
Hydrogen	(%)	3.45	2.70
Nitrogen	(%)	0.59	0.46
Sulfur	(%)	0.17	0.13
Ash	(%)	8.20	25.00
Oxygen	(%)	15.66	12.23
Chlorine	(%)	0.03	0.02
Total	(%)	*100.00*	*100.00*
ELEMENTAL ASH ANALYSIS	**PERCENT BY WEIGHT – OXIDES (AS RECEIVED)**		
Silicon Dioxide	(%)	38.61	74.58
Aluminum Oxide	(%)	16.97	9.16
Titanium Dioxide	(%)	0.81	0.43
Ferric Oxide	(%)	7.12	4.18
Calcium Oxide	(%)	23.75	6.32
Magnesium Oxide	(%)	3.54	1.32
Potassium Oxide	(%)	1.02	1/21
Sodium Oxide	(%)	0.66	0.65
Sulfur Trioxide	(%)	5.07	1/36
Phosphorus Pentoxide	(%)	0.48	0.24
Strontium Oxide	(%)	0.23	0.07
Barium Oxide	(%)	0.44	0.15
Manganese Oxide	(%)	0.06	0.04
Undetermined	(%)	1.24	0/29
Total	(%)	100.00	100.00
Hardgrove Grindibility	(HgI)	25	35
T250	(°F)	2,450	2,900

The innovative concept to be demonstrated in SO_2 removal is the reuse of the unreacted lime, which contains little fly ash, as a result of furnace slag removal, in the SDA. The majority of fly ash is removed in the combustor in the form of slag. A portion of the ash collected from the SDA and the FF are first slurried with water, chemically and physically activated, and then atomized in the SDA vessel for second-stage SO_2 removal. Third-stage SO_2 and particulate removal occurs in the FF as the flue gas passes through the reactive filter cake in the bags.

The dry injection of limestone in the boiler, combined with the fly ash recycle system, replaces the more expensive lime required by commercial SDAs, reduces plant wastes, and increases SO_2 removal efficiency when burning high- sulfur and low-sulfur coals.

The integrated process is expected to achieve SO_2 removal greater than 90 percent, and a reduction in NO_x emissions to 0.2 pounds per million Btu. The integrated process is suited for new facilities or for repowering or retrofitting existing facilities. It provides an alternative technology to conventional pulverized coal-fired boiler flue gas desulfurization (FGD) and NO_x reduction processes, while lowering overall operating costs and reducing the quantity of solid wastes.

Subbituminous coals from the adjacent UCM will be the fuel. The primary fuel to be fired is a blend of ROM and waste coals. ROM coal is a subbituminous coal with a nominal higher heating value (HHV) range of 7,815 Btu/lb, a low average sulfur content of 0.17 percent, and an average ash content of 8.2 percent. ROM coal properties are fairly uniform. The waste coal is either a lower grade seam coal or ROM contaminated with overburden material having a nominal HHV of 6,105 Btu/lb, average sulfur content of 0.13 percent, and average ash content of approximately 25%. However, waste coal properties vary. The coal handling system provides coal to both units. It is capable of providing the same or different coal blends to either unit. The actual properties of the coal blend will vary considerably as a result of the blend and particular waste coal.

III. PROJECT STATUS

The Cooperative Agreement project cost is $242 million with $117.3 million being funded under the Agreement by the DOE, and the remainder a combination of State grant, interest earnings, contributions from project participants, bonds sold by AIDEA, and power sales. The projected project cost is about $267 million. Construction of the HCCP began in the spring of 1995, and was completed in November of 1997.

Project construction was undertaken in stages due to the hostile winter conditions at Healy. The objectives of 1995 were primarily to complete all foundation work, the underground circulating water system piping, and primary structural steel. A shutdown of five months was subsequently planned for winter weather. The objectives of 1996 were to complete structural steel erection; install major equipment such as the combustors, turbine-generator, boiler, and SDA system; and to enclose the unit so that the additional mechanical and electrical equipment installation, and electrical and piping work could be accomplished in a controlled environment. The building enclosure was completed in November 1996. The main construction was completed ahead of the contractual schedule, with start-up activities commencing in the fall of 1997. Coal firing commenced in January 1998. Demonstration testing and reporting of the results has started.

IV. OVERALL DEMONSTRATION PROGRAM GOALS

Emissions control performance of the TRW Entrained Combustion/Joy-Niro Activated SDA System is projected to equal or exceed that of fluid-bed boilers (with advanced SO_2 and NO_x removal processes) or pulverized coal (PC)-fired boilers (also with advanced SO_2 and NO_x control processes). In addition, the emissions control technologies demonstrated by the HCCP are expected to be technically competitive with Integrated Gasification Combined Cycle (IGCC) power plants (also currently undergoing demonstration), but less costly to install and operate.

Demonstration of SO_2 removal efficiencies, nominally 90 percent with low reagent consumption, will allow the combined TRW/Joy-Niro integrated system to be effectively used in areas where a minimum 90 percent reduction is required and to compete with other high-removal-efficiency processes that are more costly. Waste disposal will be made easier by the production of a vitreous slag waste from the combustors and a dry powdery waste from the SDA system. The combined waste material will make a high-strength, stable waste material that can be easily disposed of in a conventional landfill operation or potentially used in commercial applications such as road base material.

The HCCP combustion system has the capability to limit NO_x emissions in the 0.20 to 0.35 lb/MMBtu range from new and existing boilers. Uncontrolled emissions of SO_2 can be reduced below National Source Performance Standards (NSPS) levels for either existing power plants or new coal-fired power plants with the TRW Entrained Combustion System alone, for some coal/sorbent combinations, or to even lower SO_2 emissions levels, when implemented with the Joy-Niro SDA technology on the back-end flue gas stream.

Project goals include demonstration of the following advantages of the integrated HCCP combustion and air pollution control systems:

- The integrated system will reduce emissions of SO_2, NO_x, and overall particulate matter, typically below 10 microns in size (PM_{10}), to levels below NSPS requirements.

- The process will demonstrate SO_2 reduction by limestone injection into the furnace. The overall use of limestone will be less than that for atmospheric fluidized-bed technologies, thereby reducing problems associated with plant wastes and reducing reagent demand and cost.

- The project will demonstrate activation and utilization of TRW-generated FCM waste for SO_2 removal in the Activated Recycle SDA System. In most SO_2 control processes, the calcium-based product from the particulate collection equipment is sent to disposal. In this innovative process, the product is reused to provide additional SO_2 removal in the SDA system.

- The project will demonstrate performance improvement and applicability of reuse of FCM to other FGD systems. For example, a utility already using FCM at one unit can make effective use of the FCM waste from another nearby site. As part of other HCCP agreements, FCM will be injected into GVEA's adjacent Unit No. 1 to reduce SO_2 emissions.

- The combustor/boiler bottom ash and SDA waste from the HCCP will be less costly to dispose of than waste from a conventional wet scrubber system. The potential for utilization of HCCP combustion process wastes as commercial by-products will also be characterized during the demonstration.

- Low-NO_x emissions will be obtained without the use of ammonia-based compounds and associated ammonia storage and emissions problems common to technologies such as selective catalytic reduction.

- A comparison of slagging combustor performance at the full scale with the Cleveland 35-MMBtu tests and the Capistrano precombustor tests will be made.

- A comparison of HCCP Operation and Maintenance (O&M) costs with those from comparable commercially available technologies will be made.

The key elements of the test program relate to the slagging combustor, the SDA system, and coal blending. The specific goals for each are described below.

V. TRW TECHNOLOGY DEMONSTRATION PROGRAM

The test plan for the TRW Coal Combustor Characterization Tests comprises three phases:

1. Initial Performance Characterization Tests
2. Operating Envelope Characterization Tests
3. Steady-State Operation Characterization Tests

Initial Performance Characterization Tests

The objective of the Initial Performance Characterization Tests is to establish the baseline performance of the combustion system while burning Performance coal (50% ROM/50% Waste). Key performance goals are:

- Stack emissions close to predicted values
- No major slag accumulations on internal surfaces
- Continuous slag removal

During this first phase of the test series, the combustor performance will be evaluated at the nominal "design" operating conditions specified for Performance Coal. It is anticipated that variations will be made in the key combustor operating conditions, including slagging stage stoichiometry, precombustor stoichiometry, slagging combustor/precombustor coal split, and slagging combustor inlet velocity. The operating range will be limited to that required to achieve reasonable performance of the combustor in terms of gaseous emissions at the stack, slagging behavior, and slag recovery. During this phase of testing, an "on-line" method for observing slagging behavior will be evaluated. Specifically, the coal flow will be shutoff after several hours at steady-state conditions and the slag coverage will be observed under oil-only firing conditions by looking through the aspirating doors located in the slag tap, tangential inlet and slagging combustor headend, as well as the furnace doors. If this method of observing slagging behavior is successful, then the number of full shut-downs required to observe slagging behavior can be reduced and the test frequency can be increased.

This initial phase of the test series will be deemed complete when the combustor can operate for extended periods of time with continuous slag removal, without any major slag accumulations on the internal surfaces, and stack emissions are reasonably close to predicted values. At this stage, the combustion system will be ready to support SDA and coal blend characterization testing.

Operating Envelope Characterization Tests

The objective of the second phase of the test series is two fold: (1) characterize the performance of the combustor over a broad operating envelope and (2) optimize the performance of the combustor for the integrated plant system at Healy. Key performance goals to be achieved during these tests are:

NO_x:	0.2 to 0.35 lb/MMBtu
Carbon Losses:	<1%
Slag Recovery:	>80%
Slagging Behavior:	No major growths or fouling

The proposed test matrix is shown in Table 2. This test series will focus on evaluating the combustion system performance over a wide range of operating conditions to determine the operating envelope in terms of stoichiometry (both precombustor and slagging combustor), precombustor exit conditions (temperature, stoichoimetry, and velocity), coal feed characteristics (coal carrier flowrates, coal grind), limestone Calcium/Sulfur (Ca/S) ratio, furnace stoichiometry, and plant load.

In order to map the combustor and boiler operating envelope, each of the operating variables will be varied independently during this characterization test series. The data from this phase of the test series will be used to (1) determine the boundaries for each operating parameter, (2) provide a basis for comparison of the HCCP combustor performance to that of the TRW Cleveland 35 MMBtu/hr combustor tests to verify scaling methodology, as well as extrapolation to other coal types and process conditions, and (3) determine the optimal operating conditions for long-term commercial operation at Healy.

Table 2.

Combustion System Operating Envelope Characterization Test Matrix

Operating Parameter	Operating Range	Performance Parameter
Slagging Combustor Stoichiometry	0.85 to 0.91	Gaseous Emissions Slagging Behavior Slag Recovery Heat Load
Precombustor Stoichiometry	0.87 to 0.99	Gaseous Emissions Precombustor Slagging Behavior Precombustor Heat Flux Gas Temp at Inlet to Slagging Combustor
Slagging Combustor/Precombustor Coal Split	36 to 42%	Same as above
Slagging Combustor Inlet Velocity	250 to 340 ft/sec	Pressure Losses Slagging Behavior Slag Recovery Heat Load
Limestone Ca/S ratio	2 to 3	Feed System Stability SO_2
Coal Blend and Grind	Performance Blend, Max Waste Coal Blend, Two Bull Ridge 50% to 70% through 200 mesh	Slag Recovery Carbon Content inSlag Carbon Content in Fly Ash CO and Smoke Limits Coal Feed Stability Heat Load Slagging Behavior
Coal Carrier/Mill Air Split	To Be Determined	Coal Feed Stability Slagging Behavior Slag Recovery Carbon Content In Slag
NO_x Post/Precombustor Air Split	Nominal + 15%, -15%	NO_x
Furnace Excess Air	Max. to Min.	CO and smoke limits Furnace-Deposits Boiler Efficiency
Load Range	50 to 100%	Stoichiometry and Air Flow Rate of Change of Load Steam Control Slagging Behavior Slag Recovery

The test matrix comprises individual variable "tests." In general, each operating parameter identified will be varied individually. The specific order in which the tests are performed will be dependent on the baseline performance determined during the first phase of the characterization tests. In general, the following test guidelines will be followed:

- If initial stack emissions and slag recovery are close to predicted levels (i.e., NO_x <0.35 lb/MMBtu and Slag Recovery >70%), then the test matrix will be set up to evaluate and optimize performance with a coarser coal grind. In this case, the coal grind will be changed to a coarser grind first and then the stoichiometry, inlet velocity, coal split and carrier air split will be optimized for the coarser coal.

- If initial stack emissions are at reasonable levels, but the slag recovery is low (<50%), the coal grind will be changed to a finer size (typically, a finer size will improve slag recovery). The stoichiometry, coal split, and inlet velocity will then be optimized for the new coal grind.

- If initial stack emissions for NO_x are higher than predicted values, then the emphasis of the test matrix will be placed on stoichoimetry, coal split, and air split variations.

Steady-State Operation Characterization Tests

The objective for the third phase of the test series is to evaluate the "optimized" combustion system operating conditions during longer term, steady-state operation.

After determination of the "best" operating conditions for the combustor system based on the results of the second phase of the test series, two steady-state tests will be conducted, one at part-load and one at full-load. The specific operating conditions will be determined based on the second phase of the characterization test results.

Representative slag samples will be analyzed to confirm environmental characteristics (i.e., non-leachable, non-hazardous). This analysis will provide useful information regarding potential commercial applications, as well as meeting environmental requirements for disposal. Although there currently are no commercial uses for the slag generated at the Healy site, potential uses at other locations include recycling as a construction material additive (e.g., concrete mix aggregate, asphalt road paving material, etc.), abrasives, and architectural media (e.g., ceramic roofing tiles). The viability of these potential applications are all site specific.

At the end of the part-load and full-load operational tests, the system will be shutdown to allow a full inspection of the slag coverage on the internal combustor walls.

VI. B&W/JOY-NIRO SDA DEMONSTRATION PROGRAM

SDA Technology system characterization refers to the tests recommended for study of how the SDA system responds to incremental change in process conditions. The SDA technology characterization test program assumes that the parameters given in Table 3 are achievable and that the equipment and control system can accommodate these variables. The characterization test matrix is subject to changes at anytime within the given outlines pending the evaluation of the previous test results and their agreement with the project goals. Additionally, characterization test parameters may need to be adjusted once data from combustor optimization are available.

Initial Performance SDA System

A brief series of tests will be conducted on the SDA/Fabric Filter (FF) system for preliminary adjustment of operating parameters. This initial performance tuning is required to ready these systems for compliance testing.

SDA/FF Characterization Testing

Table 3 summarizes the characterization testing matrix.

The following information is required for SDA/FF Technology Characterization testing:

- Coal feed rate, coal analysis, limestone feed rate, and limestone composition.
- Air heater hoppers drop out solids analysis.
- Ash analysis for alkaline components.
- FF recycle stream analysis.
- FCM – Sample at inlet to SDA for available calcium oxide.
- Recycle slurry for available calcium oxide/calcium hydroxide and reactivity.

The testing will explore SDA operation with different SO_2 inlet concentrations to the SDA based upon various levels of sulfur removal achieved in the TRW combustors, coal quality, and plant load.

Table 3.

HCCP SDA Technology Characterization Test Matrix

Inlet SO_2 Concentration	Reagent Ratio (Ca/S)	Approach to Saturation (°F)	Recycle Grind	Recycle
Low	1.95 1.75	33 18	Design	No Supplemental Heat Activation With Supplemental Heat Activated
Medium	1.95 1.75	33 18	Design	No Supplemental Heat Activation With Supplemental Heat Activated
High	1.95 1.75	33 18	Design	No Supplemental Heat Activation With Supplemental Heat Activated

These tests will be conducted at various plant loads. Sulfur capture will be characterized throughout the system including the combustors, SDA, and fabric filter.

VII. COAL BLEND TESTS

A series of coal blend tests will also be conducted at the HCCP. These tests will be conducted once the SDA characterization tests are complete. The purpose of these tests is to demonstrate unit performance with a range of ROM and waste coal mixtures.

Three coal ratios will be evaluated:

1) 100% ROM coal;
2) Blend (1) to be determined;
3) Blend (2) 65% waste coal and 35% ROM coal.

The first is ROM coal, which will provide unit performance information without a waste coal fraction. Blend (1) will be determined during the tests. It may be Performance coal or other blend. AIDEA is evaluating using a blend similar to the Two Bull Ridge blend, which will be used in future operation of this plant. Blend (2) is the HCCP coal used for design (65% waste/35% ROM).

VII. OPERATIONAL EXPERIENCE AND COMMERCIALIZATION

Training of GVEA operators has been ongoing for several months. This has included on-the-job training, classroom instruction by the AIDEA team including vendors, and participation and witnessing of construction tests. GVEA is providing operators for start-up and the current coal firing and will gradually assume day-to-day operational control of HCCP during 1998. Training is complicated by the need to provide skilled operators for HCCP without hindering Unit No. 1 operation. Temporary operators have been employed by GVEA for use on Unit No. 1. Prior to commercial operation which is scheduled for January 1, 1999, a 90-day commercial operating test will be witnessed to assure compliance with the AIDEA/GVEA Power Sales Agreement. This test will be witnessed by a third party consultant to assure compliance with the AIDEA/GVEA Power Sales Agreement and performance and reliability consistent with prudent utility practice.

During the first two years of operation, visibility monitors will be operated at two locations near the site. These monitors will be linked to the HCCP control room so that the HCCP operators may observe the stack plume and local air quality at all times. Ambient monitors will be installed after demonstration testing at selected sites. In addition, the National Park Service is conducting monitoring and biological impact studies.

Operational experience on oil has been good. The combustor oil ignition and burner systems for the combustors have operated well with minimal problems. Oil- and coal-firing related control and safety systems have been checked out and functioned without problems. At the time of preparation of this paper, each combustor had been fired on coal successfully. Both combustors have also been operated in parallel at loads up to 30 MW. The bottom ash system has been operational and the combustors appear to be slagging as expected, with no ash buildups.

Commercialization of the systems is highly dependent upon the success of the demonstration program. TRW and UCM have jointly had preliminary discussions with potential utility users in the Pacific Rim. An engineer from an overseas utility plans to participate in the technology tests. These discussions have advanced interest in the technology. TRW and UCM have determined that business development activities should continue and are actively urging potential technology users to observe the demonstration testing.

VIII. SUMMARY

The demonstration program described in this paper is the current plan. Actual testing will vary depending upon performance of the equipment, available schedule, frequency of outages, and funding and support from the technology suppliers. Since the HCCP is a large unit in the GVEA system, the demonstration test program must be carefully coordinated with GVEA operational and spinning reserve requirements. The project participants are committed to attaining the demonstration test program goals. The technologies to be demonstrated have performed successfully to date.

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Presented on behalf of Air Products, FirstEnergy, and Geneva Steel
with the concurrence of HIsmelt® Corporation Pty Limited
Geneva Steel
Provo, Utah, USA

ABSTRACT

Driven by environmental concerns and a growing metallurgical coke shortage, the U.S. steel industry is seeking a clean "coke free" direct iron process which utilizes U.S. raw materials. Expediting this move, the Department of Energy, through Clean Coal V, is sponsoring "Clean Power from Integrated Coal/Ore Reduction" (CPICOR). The CPICOR Management Company under FirstEnergy, Air Products and Geneva Steel is enacting its due diligence in the comparative investigation and analysis of direct ironmaking processes.

Direct Ironmaking processes analysed to date include COREX®, AISI, Romelt, Cyclone Converter, DIOS, Technored and HIsmelt®. HIsmelt® is highlighted in this paper because, following a major structural change from a horizontal to a vertical smelter, extensive testing has demonstrated the process as ready for commercialization.

CPICOR's interest in the commercialization of HIsmelt® is because the high level of post combustion and effective heat transfer, demonstrated in the pilot plant, offers the economical potential of using Western coals and ores in an environmentally acceptable manner to produce high quality iron.

Acknowledgments

CPICOR Management Company (CMC) gratefully acknowledges HIsmelt® Corporation Pty Limited for their support and assistance in the development of this paper. CMC claims no rights to the HIsmelt® technology or its development.

CPICOR™ DIRECT IRONMAKING PROCESS

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I. BACKGROUND

Steel Industry

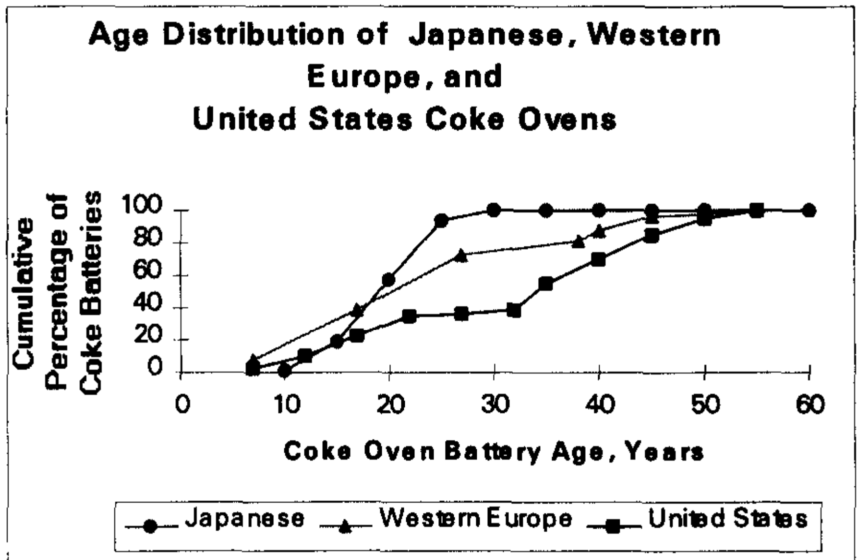

Figure 1-- Age of Coke Plants

The impact of successive environmental requirements combined with an aging coke industry[1] (Figure 1) has expedited U.S. coke plant closure causing a growing dependence on foreign coke imports and the potential for a major coke crisis. Internationally the major exporters, the Chinese, have increased their metallurgical coke exports to over some 16 million tons per year, to support the current U.S. and European shortage. Cognizant of this critical dependence, the U.S. must seek industrial independence through commercialization of its own vast coal and iron ore supplies in the expedited development of direct "coal-based" ironmaking technologies.

Geneva

Geneva's need for direct ironmaking is driven by a need to reduce operating costs through the use of local raw materials, by its growth in steel production and by a shortage of coke. Situated in North Central Utah, Geneva has abundant local iron ores and coals. In the past fifty years, however, these ores have been selectively mined leaving behind ores which are high in alkalis and phosphorus. The high alkali content together with a need to increase productivity makes these degradable ores unsuitable for blast furnace operation, requiring Geneva to purchase and transport iron ore pellets from Minnesota. Geneva's supply of Western mid-volatile coking coal ceased operation in the early 1990's with the closure of the Mid-Continental (Colorado) mine. This closure required Geneva to purchase and transport metallurgical coals from the Eastern states. This extended transportation of Eastern coals and pellets presently places Geneva at a cost disadvantage. To counter this, a move back to local raw materials through a direct ironmaking process has become essential as a means to lower operating costs.

Geneva's decade of modernization, while substantially lowering blast furnace coke rates, has encountered an increased demand for imported coke due to a near doubling of steel production. Geneva's coke rates, through oxygen and fuel injection have, in the last decade, been substantially lowered from 880 to 730 lbs per net ton of hot metal (see Figure 2). Although the coke usage per ton of iron has been reduced, the required increase in blast furnace iron production to around 7,000 tons per day has overcome the savings in coke requirements causing Geneva to become a net importer of foreign coke.

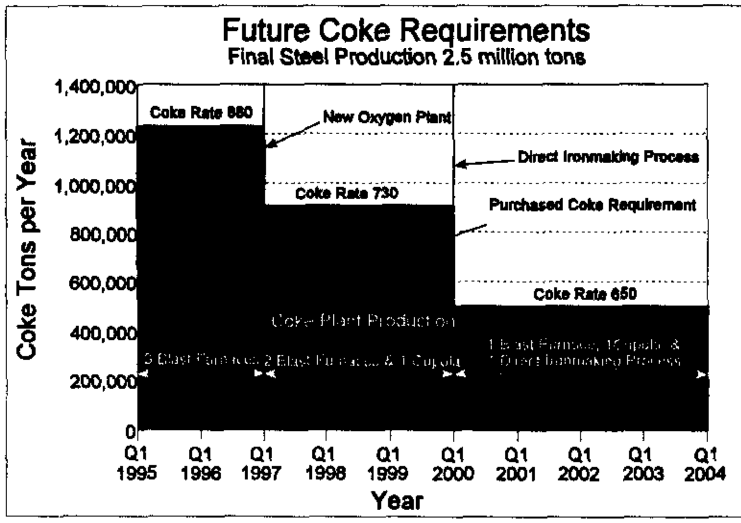

Figure 2-- Future Coke Requirements

Geneva's present goal is to increase its productivity while seeking means to lower costs and become independent from foreign coke supplies. While a direct ironmaking process could allow Geneva to reactivate the use of local raw materials and attain long term strategical and profitable operation, no commercial process is presently suitable. Geneva is therefore examining new processes under development to assess their potential to economically utilize its local raw materials for iron production.

CPICOR

CPICOR, (Clean Power from Integrated Coal/Ore Reduction) is a Clean Coal V project sponsored by the United States Department of Energy (DOE) to produce power and iron directly from United States coals and iron ores. Geneva Steel, Air Products and FirstEnergy, are the companies within the CPICOR consortium selected by DOE who have aligned to demonstrate and commercially apply a cokeless, direct ironmaking technology for this project. Geneva, as the steel arm of the consortium, was elected to analyze the global assortment of new direct ironmaking technologies and to recommend which process was most adaptable to Western and U.S. raw materials.

COREX® - RAW MATERIALS VAI

Quality of Coals

	Coals for Blending	Coal or Coal Blends: Tolerable	Coal or Coal Blends: Preferred
Moisture			
Before Dryer	max. 15%	max. 15%	< 10%
After Dryer	max. 6%	max. 5%	<5%
Proximate Analysis (wf)			
Fixed Carbon	min. 60%	min. 55%	60-70%
Volatiles	max.40%	max. 35%	20-30%
Ash	max.30%	max. 25%	5.0-12%
Sulfur (wf)	max. 2%	max. 1%	<0.5%
Grain Size	0-50 mm	0-50 mm > 50%+10 mm < 10%-2 mm < 5%-1 mm	5-40 mm > 50%+10 mm

COREX®

Figure 3-- VAI Coal Specifications

In the late 1980's, claims by Voest-Alpine Industrieanlagenbau (VAI) made the COREX® appear suitable for using Geneva's local raw materials. In the early 90's, however, coal specifications required by VAI limited the process from the full use of 100% Western coals (Figure 3) and trials at the Pohang plant in Korea were limited and inconclusive in the use of raw ores. CPICOR, thus, chose to examine alternative direct ironmaking processes inclusive of the AISI direct ironmaking, DIOS, Romelt, Tecnored, Cyclonic Smelter and HIsmelt®. For Geneva's specific raw materials, the Australian HIsmelt® Process appears to offer good economic and operational potential as well as the prospect of rapid commercialization. The HIsmelt® Process has been demonstrated in Kwinana, Western Australia by Rio Tinto and uses 100% granular coal and 100% fine ore. CPICOR Management Company is thus analyzing HIsmelt® as a leading potential direct ironmaking process.

II. THE HISTORY OF HIsmelt®

Conceptualization of the HIsmelt® Process began in 1981, followed by a partnership between CRA Limited of Australia and Klockner Werke of Germany to develop the process. A small pilot plant (10 to 12,000 tonnes per annum) was built in Germany in 1984, using a bottom-blown reactor vessel, which was operated for six years. During this time, Klockner withdrew from the project and Midrex Corporation joined CRA to form HIsmelt® Corporation Pty. Limited. In 1991, HIsmelt® began construction of a larger scale pilot plant (100,000 tonne per annum), of the same basic design, in Kwinana, Western Australia. The first hot metal was tapped in October, 1993. Since October, 1994, the process development has been under the direction of CRA, which merged with RTZ, to form RTZ-CRA whose name has since been changed to Rio Tinto. In 1996, the decision was made to change the pilot reactor to a fixed water cooled vertical smelt reduction vessel with top injection of raw materials.[2,3]

To date, the vertical vessel reactor has operated under two major test campaigns. The first was a 12 day continuous run followed by a second 38 day continuous run producing a total of 8,654 tons of high quality pig iron. Availability of the process during each of these runs was over 98%.[4]

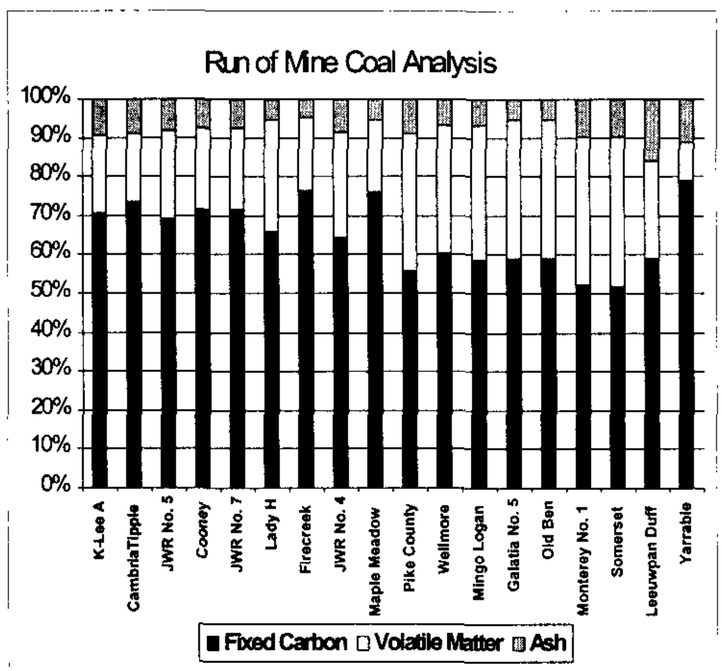

Figure 4-- Coal Analyses

The majority of the testing has been run using the "Yarrabie" coal compared in Figure 4 to U.S. coals. Continuous, stable operation has also been acheived using a highly oxidized, medium volatile bituminous "Leeuwpan Duff" coal from South Africa which is very similar to many readily available U.S. coals (see Figure 4).

for the reduction and smelting of iron oxides. The process has consistently demonstrated 60% post combustion levels with 90% heat transfer efficiency. A simplified process flow for the HIsmelt® is illustrated in Figure 5.[3]

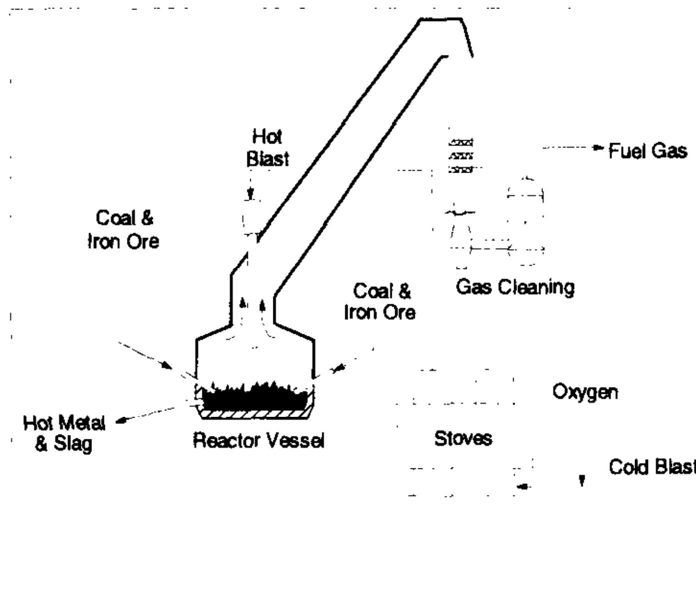

Figure 5-- Simplified HIsmelt® Process Flow

The HIsmelt® Process utilizes a vertical smelt reduction vessel, which is a closed molten bath reactor into which iron ore fines, coal, and fluxes are injected. Coal, which can be of a wide range of composition, is injected into the bath where carbon is rapidly dissolved. The dissolved carbon reacts with oxygen from incoming iron ore to form carbon monoxide and metallic iron. Injection gases and evolved CO entrain and propel droplets of slag and molten iron upward into the post combustion zone.[3]

The iron reduction reaction occurring in the molten bath is endothermic, absorbing heat, so additional heat must be generated and returned to the bath to sustain the reduction process and maintain an acceptable hot metal temperature. This is achieved by post combusting the carbon monoxide and hydrogen from the bath with oxygen-enriched hot air blast entering through the central top lance. The heat released from the post combustion reaction is absorbed by the metal and slag droplets and returned to the bath as the droplets descend under gravity (see Figure 6). Droplets in contact with the gas in the post combustion zone absorb heat, but are shrouded during descent by ascending reducing gases which, together with bath carbon, prevent unacceptable levels of slag FeO.

The molten iron collects in the bottom of the bath and is continuously tapped from the vessel through a fore-hearth, maintaining a constant level of iron inside the vessel. Slag, which is periodically tapped through a conventional blast furnace-type tap hole, is used to coat and control the internal cooling system and reduce the heat loss (see Figure 6)

Reacted hot gases, mainly N_2, CO_2, CO, H_2 and H_2O, exit the vessel. After scrubbing, the gases can be further combusted to heat the hot blast stoves or used to generate steam for power generation. The gases can also be used to pre-heat and partially pre-reduce incoming iron ore.

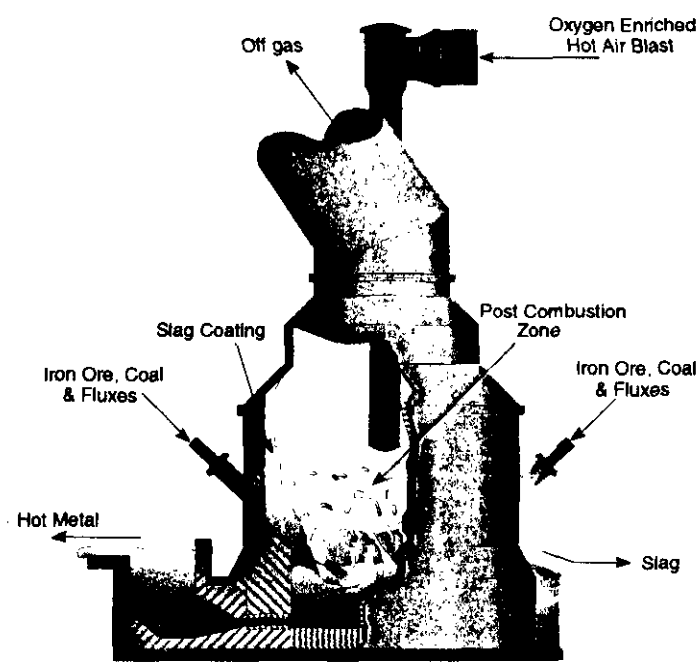

Figure 6-- HIsmelt® Vertical Reactor

periodically tapped through a conventional blast furnace-type tap hole, is used to coat and control the internal cooling system and reduce the heat loss (see Figure 6)

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Advantages

Ironmaking using HIsmelt® has many advantages, enumerated as follows:

1. Agglomeration of feed material is not required. The process injects fine grained iron ore, reverts and granular coal directly into the metal bath after drying.

2. Alkali problems associated with blast furnaces are eliminated by the high temperature profile within the smelter which exceeds that at which alkalis condense. This makes the process amenable to high-alkali Western iron ores and coals.

3. The high level of post combustion can generate sufficient supplemental heat to effectively use a wide range of U. S. coals, including Western high-volatile bituminous coals.

4. The post combustion system offers the ability to adjust the offgas calorific value through varying the quantity of coal injected into the molten bath.

5. The single vessel eliminates the need for the inter-stage cooling of gases which greatly simplifies the process.

6. The HIsmelt® operational flexibility makes it responsive to short-term downstream steelmaking problems because it can be rapidly shut down and easily restarted.

7. The cracking of coal volatiles in the high temperature molten bath eliminates the solid waste streams and emissions associated with traditional coke plant operations.

8. Dust losses from the process are captured and recycled, improving process efficiency and eliminating the need for revert piles.

9. The process can use existing blast furnace stoves and blowers and the coal crushing system made redundant at the coke plant.

Commercialization

The HIsmelt® Process is ready for commercialization. Through the test work done at Kwinana, the commercial viability of the total process has been successfully demonstrated. Operational control parameters have been identified and complete computer control models have been successfully developed and proven. It is Rio Tinto's goal to have a fully operational, commercial plant in the market place early in the next decade. HIsmelt® has committed resources to refining the process to ensure this transition from development to commercialization is successful.(3)

HIsmelt® is continuing at its Kwinana plant to make refinements to further enhance the process, simplify the engineering and verify refractory life. Investigations are also continuing in exploring methods of reducing energy requirements and increasing productivity to reach optimum economical production efficiency.(3)

Planned or Possible Additional EAF Capacity in U. S.

Steelmaker	Melting Capacity (NT/Year)	Year
* Armco, OH	800,000	1995
Bayou, LA	200,000	1995
* Beta Steel, IN	1,000,000	1995
* Caparo Steel, PA	800,000	1995
* Gallatin Steel, KY	1,000,000	1995
* Nucor Steel, IN	400,000	1995
Total 1995	**4,200,000**	
Nucor Steel, NE	200,000	1995-6
BRW Steel, PA	750,000	1996
* Ipsco Steel, IA	1,000,000	1996
* North Star/BHP Steel, OH	1,500,000	1996
North Star, AZ	500,000	1996
* Steel Dynamics, IN	1,200,000	1996
* Trico Steel, AL	2,200,000	1996
Total 1996	**7,350,000**	
Stafford Rail, Miss. River	450,000	1996-7
Cascade Steel, OR	250,000	1996-7
* Chaparral Steel, no site	600,000	1996-7
J&L Structural, PA	300,000	1996-7
Lone Star Steel, TX	300,000	1996-7
* Nucor Steel, SC	700,000	1996-7
* Tuscaloosa Steel, AL	1,200,000	1996-7
Birmingham Steel, TN	1,000,000	1997
Qualitech Steel, AL or TX	550,000	1997
Total 1997	**5,750,000**	
CF&I Steel, CO	200,000	1997-8
* Gallatin Steel Phase II	1,000,000	1997-8
* World Class Steel, PA	750,000	1997-8
Total 1998	**1,950,000**	
* Beta Steel Phase II	1,000,000	1998-9
* Steel Dynamics Phase II	800,000	1998-9
* Nucor Steel Phase II	1,000,000	1998-9
Total 1999	**2,800,000**	
Grand Total	**22,050,000**	

* Indicates flat rolled capacity (total 17,450,000 net tons)

Figure 7-- EAF Capacity

Commercialization of the HIsmelt® Process, if undertaken through DOE Clean Coal V program, would be in two phases. The combined phases would produce some 1.2 million tons of hot metal per year with the surplus offgas being used for high efficiency power generation of around 120 MW. Oxygen requirements have been estimated at 2,000 tons per day.

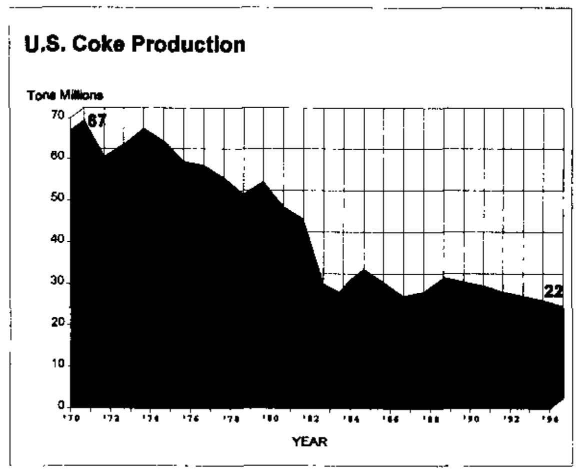

Figure 8-- U.S. Coke Decline

IV. FUTURE OUTLOOK

The U.S. momentum behind the commercialization of direct ironmaking is driven by the decline of metallurgical coke production, by the shortage of obsolete scrap and by the growth of United States steelmaking. The United States could be some 55 million tons of steel short within the next 10 to 15 years. *New Steel*, April 1997, showed steel imports to the United States to have increased from 24.409 million tons in 1995 to 29.164 million tons in 1996. *33 Metal Production*, October 1995, shows some planned or possible additional EAF capacity of 22 million tons (Figure 7). Figure 8 shows the decline of the coke production from 1970 to 1994 while Figure 9 shows the predicted shortage of coke up to the year 2011. Presuming by the year 2010 a 10 million ton shortage of coke is experienced, this shortage translates to 25 million tons

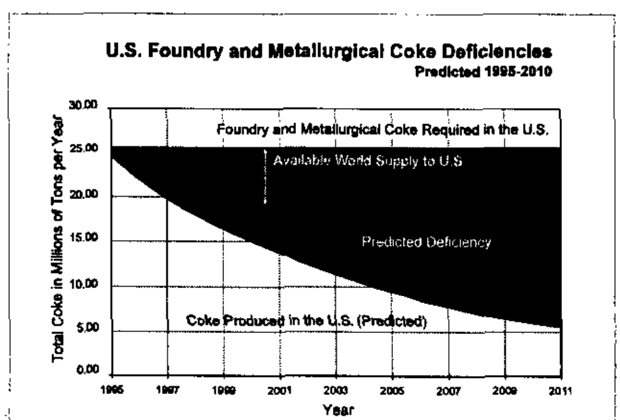

Figure 9-- Predicted Coke Deficiency

of steel at a coke rate of 800 lb/NTHM. If the global scrap shortage is predicted to be around 130 million tons by 2010, then much of the United States market shortfall of 55 million tons will have to be made up by environmentally acceptable new coke plants, direct reduced iron or direct ironmaking[5].

Activity in all these fields in the United States should be increasing over the next two decades with potential requirement for over 20 direct ironmaking units. The HIsmelt® Process, now on the verge of full commercialization, offers the environmental compatibility and raw material flexibility to place it as one of the leading contenders in direct ironmaking technology.

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CONCURRENT TECHNICAL SESSION II

CLEAN COAL DIESEL TECHNOLOGY DEMONSTRATION UPDATE

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PAPER UNAVAILABLE AT TIME OF PRINTING

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MICRONIZED COAL REBURNING DEMONSTRATION OF NO_X CONTROL

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ABSTRACT

The Micronized Coal Demonstration Project is part of Round 4 of the U.S. DOE's Clean Coal Demonstration Program. Originally planned for demonstration at TVA's Shawnee Plant, the demonstration was transferred to Eastman Kodak Company (Kodak) and New York State Electric & Gas Corporation (NYSEG). The project includes the demonstration of micronized coal reburn technology for the reduction of NO_x emissions from a cyclone boiler at Kodak. The cyclone boiler application includes the utilization of a retrofit Fuller MicroMill™ to provide micronized reburn coal.[1] The technology is also to be demonstrated on a 150 MW class tangentially-fired boiler at NYSEG's Milliken Station. Milliken will utilize an existing DB Riley MPS mill with dynamic classifier to provide the reburn fuel. This paper provides an update on the current status of the project with emphasis on test results and operating experiences.

I. INTRODUCTION

The concept of coal reburning was first demonstrated in the US in 1991-1993 at Wisconsin Power & Light's Nelson Dewey Station on two 100 MW cyclone boilers. Since the compliance date for the Group II boilers (cyclone, vertically fired, wet bottom and cell burners) is January 1, 2000, interests in reburning technology started to surface recently.

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[1]Micromill is a trademark of the Fuller Company

In September, 1991, the United States Department of Energy selected a micronized coal reburning project for funding in Round 4 of its Clean Coal Technology Demonstration Program (CCTD). The Micronized Coal Reburn Project for NO_x Control on a 175 MW wall fired Unit was to be demonstrated at TVA's Shawnee Plant. The project was subsequently relocated to NYSEG's Milliken Station and Kodak's #15 Boiler in December 1995. Project team members include CONSOL Inc., D.B. Riley, Fuller Company, Energy and Environmental Research Corporation (EER), and ABB Combustion Engineering, Incorporated. Project cofunders include DOE, Kodak, NYSEG, New York State Energy Research and Development Authority (NYSERDA), and Empire State Electric Energy Research Corporation (ESEERCO).

The overall project goals are:

- Demonstration of micronized coal reburning technology on a cyclone boiler with at least a 50% NO_x reduction.
- Demonstration of micronized coal reburning technology in conjunction with low No_x burners on a tangentially fired boiler with a 25-35% NO_x reduction.
- Comparison of mill effectiveness and economics in micronizing coal using a Fuller MicroMill and a D.B. Riley MPS 150 with dynamic classifier.
- Determine effects of coal micronization on electrostatic precipitator (ESP) performance.

The host site for the cyclone boiler demonstration is Kodak's Kodak Park Site Power Plant located in Rochester, New York. #15 Boiler is a 50 MW class cyclone boiler. The host site for the tangential boiler demonstration is NYSEG's Milliken Station, located in the town of Lansing, New York. Milliken has two Combustion Engineering 150 MW pulverized coal-fired units built in the 1950's.

Cost and Schedule

This project was established to meet NO_x emissions requirements for both Milliken and Kodak's #15 Boiler, therefore the schedule was set to complete the project by 1998. The construction period for Kodak lasted from Fall 1996 to Spring 1997. During this period Kodak #15 Boiler was retrofitted with Fuller MicroMill, MCR injectors, overfire air, flue gas recirculation and burner management and controls. The operation and testing phase of the demonstration began in April 1997 and will be completed by December 1998. Milliken Station performed parametric testing on the boiler using existing equipment. The testing began Spring of 1997 and will conclude in the Summer of 1998.

The total cost of the project, including the demonstration program will be $8,683,499 and will include obligated DOE funding of $2,500,000.

Project Description

Cyclone Boiler Micronized Coal Reburn Project

Kodak's #15 Boiler is a Babcock and Wilcox Model RB-230 cyclone boiler commissioned in 1956. The unit was designed to generate 400,000 lbs/hr of 1400 psig, 900°F steam with a rated heat input of 478 MMBTU/hr at maximum continuous rating. The fuel supplied to this boiler is Pittsburgh Seam medium to high sulfur coal with a Hargrove Grind Index of approximately 55 and a high heating value of 13,300 Btu/lb. The cyclone furnaces operate at a very high heat release rate, creating molten slag which is captured on the cyclone walls and flows to a slag tap at the bottom of the furnace. Particulate control is maintained by an electrostatic precipitator.

The baseline NO_x emissions from this unit is nominally 1.25 lb/MMBTU. The MCR retrofit project is expected to lower NO_x emissions from .70 - .60 lbs/MMBTU at 400,000 lbs/hr steam, while limiting the reduction of boiler efficiency.

The design of the technology includes the installation of a Fuller MicroMill coal micronizing system, reburn injectors/burners and overfire air downstream of the main cyclone burners. The MicroMill is unique in that it uses a tornado like column of air to create a rotational impact zone where the coal particles actually strike against each other and thus crush themselves. The typical particles generated by the MicroMill will be approximately 20 microns, whereas normal pulverized coal is about 60 microns. This will increase the surface area by ninefold allowing for more complete combustion in a shorter time period. This is critical to the success of the project, since the boiler is small and has a low residence time.

The reburn system is the core technology that is being demonstrated to reduce NO_x emissions. Reburn has been used principally with natural gas or oil as the reburn fuel. Reburning of pulverized coal has been demonstrated and proven to be advantageous to the alternative fuels. The project will use true micronized coal (80% <325 mesh) for reburn fuel. EER was responsible for the design and supply of the micronized coal injector equipment and overfire air system as well as determining the expected boiler performance and NO_x emissions.

Tangentially-fired Micronized Coal Reburn

NYSEG's Milliken Station has two 150 MW units with CE designed tangential coal-firing single furnace boilers. Both units have been retrofitted with ABB Low NO_x Concentric Firing Systems (LNCFS-3™) and four new DB Riley MPS 150 pulverizers with dynamic classifiers.[2] The combination of the LNCFS-3 and MPS mills has resulted in reducing NO_x emissions from both units from a baseline of .60 lb/MMBTU to less than .39 lb/MMBTU while producing marketable fly ash with a carbon content less than 4 percent.

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[2]LNCFS-3 is a trademark of ABB Combustion Engineering, Inc.

Each pulverizer supplies one elevation of corner burners. To simulate and test a reburn application, the lower three coal elevations were biased to carry approximately 80% of the fuel required for full load. The top burner provided the remaining fuel. The speed of the dynamic classifier serving the top mill was increased to provide a micronized fuel. An incremental NO_x reduction was achieved in addition to the reduction already obtained with the LNCFS-3.

As a comparison to the NO_x reductions demonstrated with the reburn simulation, the burners were arranged to more deeply stage combustion. This simulated the ABB TFS2000R™ combustion system.[3] Whereas the LNCFS-3 utilizes close coupled and separated over-fire air injection zones, the new system has an additional zone of separated over-fire air. The result is a burner that is capable of deeper staging.

II TEST PLAN

The test plan was developed to cover all of the impacts of the micronized coal reburn demonstrations at Kodak and Milliken Station. Incremental NO_x reductions obtained by reburn have been determined and will be verified with additional testing. The effectiveness of the two micronizing systems is presently being evaluated. The change in dust loading and precipitator performance caused by the micronized fuel still needs to be determined.

Pittsburgh seam coals were burned during the demonstration testing, with the same coal used as the primary and reburn fuels. Testing was in conjunction with the optimization testing performed by ABB on Milliken Unit 1, and by EER on Kodak #15 Boiler. The boiler and operating settings were determined during the optimization testing and will be verified during future testing planned later this year.

The first phase of micronized coal reburning evaluation was conducted at Milliken Unit 1. This included using the existing top burner to feed the micronized reburn fuel into the upper reaches of the boiler using the existing mill to micronize the coal. Based on additional future testing, if test data demonstrates that a significant benefit can be derived with a separate micronized reburn system, then separate injectors will be installed to replace the existing top coal burner nozzles. Both phases of the project would involve the same tests, and utilize the LNCFS-3 test data from the Milliken Clean Coal Demonstration Project as a baseline.

Baseline and micronized coal reburning tests conducted at Kodak # 15 Boiler were at full load. Testing at reduced loads were kept to a minimum. The micronized reburn fuel was prepared using the Fuller MicroMill.

The operating variables that were modified during the tests are listed in Table 1. The parametric/optimization tests were performed on the reburning system to establish the best operational modes. Also various low and high experimental values for each optimized variable were tested to confirm operational boundaries of the system and to record the effect. The experimental

[3]TFS 2000R is a trademark of ABB Construction Engineering, Inc.

ranges of the operating conditions were adjusted to maintain reliable boiler operation and power generation. In particular, if a set of test conditions could not maintain the required steam conditions, the variables were adjusted or the test was terminated.

TABLE 1. TEST VARIABLES

Milliken Unit 1:

Boiler Load, MW
    Full Load, %

Top Elevation Coal Size, % -325 Mesh
    Mill Setting, rpm

Economizer O_2, %

[1]Fuel Air Levels 2, 3 and 4 Damper, %
[2]Top SOFA Damper, %

Top Elevation Coal Flow, % Total

Main Burner Tilt, Degrees

SOFA Tilt, Degrees

Kodak Boiler 15:

Boiler Load, MW
Full Load, %

Reburn Fuel Rates (%of total)

Micronized Coal Size, % -325 Mesh

Primary Excess Air, %
    Primary Stoichiometry (SR1)

Micronized Coal, %
    Reburn Stoichiometry (SR2)

Overall Excess Air
    Final Stoichiometry (SR3)

[1]Fuel Air Levels 1 (Top Level) Damper Position is at Minimum
[2]Bottom and Middle SOFA Damper Positions are at Minimum

Overall, the evaluation program included two test programs, corresponding to the micronized coal reburn at Milliken Unit 1 and the micronized coal reburning evaluation at Kodak #15 Boiler. Each test program consists of four test programs:

- <u>Diagnostic</u>

  These tests identify the boiler setting which provides optimized performance while maintaining minimal NO_x emissions and carbon in the ash.
- <u>Performance</u>

  These tests verify that the optimized boiler operation and performance is equivalent to the diagnostic test findings. The testing quantifies the diagnostic test performance.
- <u>Long-Term</u>

  This test monitors the operation and performance of the boiler over a 51 day period to demonstrate that the micronized coal operation of the boiler is sustainable and can maintain overall performance.
- <u>Validation</u>

  This test demonstrates that the optimized boiler operation and performance over a long period of time is repeatable.

Coal Reburning Technology for NO_x control

Coal Reburning is a NO_x control technology whereby NO_x is reduced by reaction with hydrocarbon fuel fragments. A typical application of coal reburning to a coal-fired boiler is illustrated in Figure 1. No physical changes to the main burners are required. The burners are simply turned down and operated with the lowest excess air commensurate with acceptable lower furnace performance when considering such factors as flame stability, carbon loss and ash deposition.

The technology involves reducing the levels of coal and combustion air in the burner area and injecting reburn fuel (micronized coal) above the burners followed by the injection of overfire air (OFA) above the reburn zone. This three zone process creates a reducing area in the boiler furnace within which NO_x created in the primary zone is reduced to elemental nitrogen and less harmful nitrogen species. Each zone has a unique stoichiometric ratio (ratio of total air in the zone to that theoretically required for complete combustion) as determined by the flows of coal, burner air, reburn fuel and OFA. The descriptions of the zones are as follows:

- Primary burner zone: Coal is fired at a rate corresponding to 75 to 90 percent of the total heat input. NO_x created in this zone is slightly lower than normal operation due to the lower heat release and the reduced excess air level.

- Reburn zone: Reburn fuel (micronized coal) is injected above the main burners through wall ports. The reburn fuel consumes the available oxygen and produces hydrocarbon fragments (CH, CH_2 etc.) which react with NO_x from the lower furnace and reduce it to elemental nitrogen, N_2. Optimum NO_x reduction performance is typically achieved when the reburn zone is operated at about 90% of stoichiometric ratio, which is slightly fuel rich (reducing). NO_x reduction can be adjusted by varying the reburn fuel injection rate, typically over the range of 10-25% of total boiler heat input. To minimize the reburn fuel required to achieve fuel rich conditions in the reburn zone, EER's design utilized injectors rather than burners, which would have introduced additional air. In addition, flue gas was recirculated (FGR) to carry the micronized fuel into the boiler. This also contributed to the fuel rich conditions in the reburn zone.

- Burnout (exit) zone: The oxygen required to burn out the combustibles from the reburn zone is provided by injecting air through overfire air ports positioned above the reburn zone. These ports are similar to conventional overfire air ports except that they are positioned higher in the furnace so as to maximize the residence time for NO_x reduction occurring in the reburn zone OFA is typically 20 percent of the total air flow. OFA flow rate and injection parameters are optimized to minimize CO emissions and unburned carbon in fly ash.

Several derived benefits can be realized with coal reburning. From an economic standpoint, coal reburning is less expensive to install and costs less to operate than selective catalytic reduction. With micronized coal as the reburn fuel, the utilization of the fuel is enhanced. This results in reduced carbon in ash, when compared to conventional coal reburning. These benefits outweigh the additional power requirements associated with operation of the micronizers and (FGR).

Kodak Test Program

The overall goal to reduce NO_x emissions to .60 lbs/MMBTU or below was achieved during the parametric test program. Several equipment problems have hampered the testing progress and will need to be resolved to make this a more reliable NO_x control program.

The testing to date has included the diagnostic testing which includes the parametric testing of the boiler. The purpose of the parametric testing is to define the relationships that exist between the controlling parameters (micronized coal flow rate, coal fineness, FGR flow rate, overfire air flow rate, coal flow biasing and soot blowing frequency) and the boiler outputs (stack emissions, carbon in ash, electrical power etc.). These relationships are used to approximate the boiler set points required for optimum reburning performance. The approach utilizes a formalized matrix consisting of a series of preplanned tests that vary one parameter at a time. It should be noted that the matrix functions as a guide only and modifications to the test direction may be required as events dictate.

The 1997 test program was divided into three periods rather than one continuous test due to problems encountered with both the boiler and reburn equipment. During the test program, process parameters such as cyclone stoichiometric ratio, reburn zone stoichiometric ratio, micronized coal flow and boiler load were varied. System performance data was collected to determine conditions which were optimum for NO_x control. The data from the tests was also used to establish optimum operational settings for the long-term test used to evaluate the long term impacts of the coal reburning system on both NO_x emissions and boiler performance. Concurrent with obtaining parametric test data, system start up test data were also acquired to provide input information for placing the reburn system in automatic control.

The first series of tests occurred during February 1997, while the system was in the startup mode. During this series of tests, boiler and operational problems occurred and included leakages from the transport gas fan due to incompatible gasket material, high mill vibration and inaccurate coal flow measurements. During this test NO_x emissions were reduced to the target .60 lb/MMBTU from the baseline level of approximately 1.25 lb/MMBTU, CO was maintained below 100 ppm at all times and loss on ignition was 21 to 24 percent at baseline and approximately 50 percent during reburning.

The boiler efficiency decreased by 1.5 percent, which was within the project limit of 2 percent decrease or less. Opacity was in the range of 17 percent at the .60 lb/MMBTU NO_x emission level.

The second series of tests occurred in the month of May 1997 following the replacement of the transport gas fan gaskets, recalibration of the feedwater and steam flow meters, balancing of the micromills to reduce vibration, and adjustments to the coal flow indicators. The target NO_x level of .60 lbs/MMBTU was achieved at micronized coal input levels of approximately 15 percent or greater. Loss on ignition increased from an average baseline level of 40 percent to approximately 60 percent at 20 percent micronized coal heat input. The 6 minute opacity average increased substantially at high micronized coal inputs but stayed below the 20 percent limit during most of the tests, except on a few occasions where baseline opacity prior to coal reburning was already higher than the typical baseline level of 5 percent. The steam temperature was maintained above the plant's preferred lower limit of 875 F at micronized coal inputs up to 20%.

The third series of tests occurred in the month of November 1997 after the swirler on the coal injectors had been removed and replaced with a view port and both the east and west mills had been realigned to reduce vibration. The target NO_x levels during these tests achieved .60 lbs /MMBTU at micronized coal inputs of approximately 20 percent or greater with acceptable opacity and steam temperature. Opacity was 10 to 12 percent during most reburning tests, a slight increase form a typical baseline level of 5 percent. The steam temperature stayed above the plant's lower limit of 875° F. Loss on ignition averaged approximately 45 percent, a 5 percent increase from the baseline level of 40 percent.

Kodak MCR Assessment

The Kodak MCR project has been successful in reducing NO_x emissions by 50 percent. Figure 2 presents the relationship between NO_x emissions and reburn coal heat input for each of the three test series. The data shown on the plots represent cyclone stoichiometric ratios in between 1.05 to 1.15. In each test series, the plots demonstrate that the project NO_x target of .60 lbs/MMBtu was achieved with as low as 17% reburn fuel heat input. Based on an average baseline level of 1.45 lb/MMBtu, the .60 lbs/MMBtu emissions level represents a 59% reduction. NO_x emissions dropped immediately upon introduction of the reburn fuel and continued to decrease as more reburn fuel was added to the boiler. The best NO_x emissions reduction for a limited period of time occurred during the second test series at a low SR_1 level and at a reburn fuel heat input of 20%. The NO_x emissions reduction level at that point was .40 lbs/MMBTU.

Figure 3 presents the same data, plotted against reburning zone stoichiometry (SR_2). The plots show that the SR_2 decreased as more micronized coal was introduced into the furnace. The NO_x target of .60 lbs/MMBTU was achieved when SR_2 reached approximately 0.9, with cyclone stoichiometry (SR_1) maintained a 1.05 to 1.15. It was predicted that the SR_2 level required to achieve the project NO_x target of .60 lbs/MMBtu would be between 0.85 and 0.90. The data show that the prediction was verified.

Figure 4 presents the relationship between loss-on-ignition (LOI) and reburn fuel heat input. The baseline during the second series of tests was 35 to 45 percent while the baseline during the third series of tests was about 25 to 35 percent. Note that the LOI level showed high variability. The higher the baseline LOI during the second test series may have been due to lower excess air levels in the cyclone. The set point O_2 was approximately 2.8 percent during these tests as compared to 3.3 percent during the third series of tests.

The plots show that LOI increased with increasing reburn fuel heat input. The increase was due to the shorter residence times of the coal in the furnace. At 20 percent reburn fuel heat input, LOI increased by approximately 5 to 10 percent from baseline during the third series of tests. This test series is considered to be more representative of coal reburning impacts on LOI. The high LOI levels during the second series of tests were due to reburn fuel maldistribution caused by slag build up on some of the coal injectors.

However, several obstacles have prevented a complete and accurate assessment of the system. Some of the problems experienced during the testing included the following:

- Fuel feed - the fuel feed to the micromill is frequently interrupted due to pluggage within the coal handling system. Coal fineness and moisture have been a problem. Since coal feed is determined by the rpm of the screw conveyor an interruption or reductions in fuel flow can not be determined readily. A rebuilt rotary feeder and air canon have been added to the system to reduce future pluggage.

- Micromills - vibration and blade wear have been chronic problems and have also resulted in interruptions to the reburn system. This system has been overhauled and will be run continuously to determine reliability and maintenance costs.

- Coal flow - since coal has flow through each injector cannot be determined, biasing for flow has not been accomplished. Flow balancing will be accomplished by calculation.

- Oxygen Accuracy - additional oxygen probes were installed from 2 probes to 6 probes.

These areas are presently being addressed in order to fully assess the system under a continuous uninterrupted operation. This information will allow full assessment of the capabilities of the system and the costs associated with the maintenance and operation of MCR on a cyclone boiler. Long term testing is scheduled to begin by mid May and end by the end of July 1998.

Milliken Test Program

As part of the Milliken Clean Coal Technology Demonstration Project Unit 1 was retrofitted with new Low NO_x Concentric Firing System (LNCFS-3) with both close coupled and separated overfire air ports to achieve up to 40% of the NO_x reduction. The burners developed by ABB C-E utilize both air staging and early devolatilization of the coal to control the combustion NO_x formation. The close coupled and separated overfire air systems have a total of five elevations of overfire air ports to allow for operational flexibility. The combined overfire air capabilities approach 40% of the total combustion air. The coal nozzles were initially designed to retain flame front by creating recirculation zones at the burner tip. These coal nozzles were later redesigned for higher sulfur coal applications by increasing the burner outlet velocity and allowing for more air cooling around the fuel compartment. A set of offset air nozzles are part of the windbox design to deliver "cushion air" between the fireball and the waterwalls in order to minimize the fireside corrosion due to a reducing environment.

Although the new equipment offers a great degree of operational flexibility, the new burner systems are more sensitive to coal quality variation than the original equipment. Higher volatility coals (>36%) can cause close ignition and coking on the burner tips. The increased sensitivity can be explained by the air staging effect which reduces the secondary air velocity to maintain the flame front distance. The operators have developed awareness of such impact and are able to respond to the coal change before problems occur.

Since Milliken Unit 1 can produce coal fineness approaching the "micronized " level, a coal reburn can be simulated on the existing LNCFS-3 burners by biasing mill loading and air dampers. This simulated reburn condition can determine if NO_x reductions can be realized for future use during ozone season and whether a full conversion to micronized coal reburn system would be cost effective. A test program was initiated to quantify the ability to reduce NO_x emissions using the simulated reburn system at Milliken.

The bulk of the testing at Milliken occurred from March 10, 1997 to April 2, 1997 with some additional testing in December, 1997. ABB-CE provided the necessary manpower, test equipment and laboratory services for ultimate coal analysis. DB Riley provided laboratory services for ASTM mill fineness analysis. Consolidation Coal Co. (Consol) provided analytical data reduction support.

In cooperating with NYSEG, ABB-CE developed a test matrix consisting of 32 separate tests based on the following progression:

- 1) What is the maximum consistently achievable NO_x emission reduction based on deep staging of the combustion ?

- 2) What is the maximum consistently achievable NO_x emission reduction based on maximum coal micronization with the top elevation mill, in addition to combustion staging ?

- 3) What is the maximum consistently achievable NO_x emission reduction based on combined top mill micronization, deep staging and next to top mill removed from service, creating a separation between the main flame and the reburn flame (true reburn configuration) ?

The primary objective during the testing was to determine the minimum NO_x level attainable while maintaining marketable fly ash. Marketable fly ash is defined as having less than 4.5 % loss on ignition. Various parametric tests were run and the resulting NO_x, LOI, O_2 values were recorded during each test.

The test data collected during the test periods have defined the impact of various settings on NO_x emissions. The following graphs capture the impact of these settings on NO_x emissions in lbs/MMBtu and the percent of carbon found in the fly ash.

The following conclusions were derived:

- 1) Effect of SOFA Tilt, (Fig. 5): Varying the tilt from 0 to 150 degrees, had practically no effect on NO_x emissions, but increased the LOI from 2.8% to 5.1%, a net increase of 82%.

- 2) Effect of Reburn Fuel Fineness (Fig. 6): Changing the upper mill classifier speed from 95 RPM to 115 RPM effects the coal fineness as well as the production rate of the mill.

  For example, in the top mill, the fineness as a function of dynamic classifier speed is shown in the table below:

CLASSIFIER FINENESS % Passing Mesh

RPM	-50 (297μ)	-100 (210μ)	-200 (74μ)	-325 (44μ)
115	100%	99.9%	95.1%	73.1%
105	100%	99.9%	90.6%	69.9%
95	99.9%	99.5%	85.2%	61.4%

  Fig. 6 demonstrates that increasing mill fineness does not affect NO_x emissions, even at various excess O_2 levels (as measured at the economizer). However mill fineness does have a significant effect on the amount of carbon found in the flyash. The finer grinds reduce significantly the % LOI in flyash, from 6.6% to 3.8%, a better than 42% improvement.

- 3) Effect of Reburn Fuel Flow (Fig. 7): Changing the reburn fuel flow of the micronizing mill (top mill) from 15% to 25% of total fuel flow has had a small impact on the NO_x emissions reduction but a large impact on the LOI in the fly ash. The NO_x emissions were reduced from 0.32 to 0.27 Lbs / MM Btu an actual reduction of about 15%, while LOI increases from 4% to 5.5%, an actual increase of more than 35%, rendering this ash unsuitable for commercial sales.

- 4) Effect of Primary Air Flow (Fig.8): Changing the primary air flow as a percentage of total air from 55% to 65%, had little effect on the NO_x emissions as well as the LOI. NO_x emission within the above range of air flow changed from 0.27 to 0.32 Lbs / MM Btu, which was an actual change of about 15% while the LOI varied from 4.2% to 3.8%, a variation of less than 10%.

- 5) Effect of Excess Air (Fig. 9): This is the single most significant parameter that affects both the NO_x emissions and the LOI. As evidenced in Fig. 9, and in the case of the top mill adjusted for regular grind (80% thru 200 mesh) an increase in measured O_2 at the economizer inlet from 2.5% to 3.75%, yields an increase in NO_x

emissions from 0.36 to 0.43 Lbs / MM Btu, or about a 20% increase. When the top mill is adjusted for fine grind (micronizing), the NO_x emissions are only marginally better.

Fig. 9 shows the dramatic impact of excess air on LOI. When the economizer O_2 is varied from 2.5% to 3.5%, the LOI, in the case of the top mill adjusted for regular grind, will drop from 6.2% to 3.8%, a reduction of almost 40%. When the same measurements are made while the top mill is micronizing, the reduction in LOI is less significant, from 4.6% to 3.8%, or less than 20%.

- 6) Effect of mill pattern (Fig. 10): When mills are numbered from 1 to 4 on this unit, with #1 mill being the top mill, then removing mill #2 will give a gross approximation of a reburn configuration by creating a gap between the main flame (mill 3 & 4) and the reburn zone (mill 1). In addition, mill 1 is set for micronizing. As can be seen on Fig.10, at a given load (120 MW), NO_x emissions increase with the number of mills in service. For the same conditions, LOI decreases while increasing the number of mills in service, this is primarily due to the load on each mill being smaller which results in a higher average fineness.

These results were deduced from the 1997 test program. During the 1998 test program the most successful tests from 1997 matrix will be selected in addition to new tests designed to research better settings likely to yield higher NO_x reduction. In addition, 3 of the 4 mills on the unit will have major overhauls, the burners at the uppermost elevation will be fitted with burner tips redesigned to better cope with the flame attachment problems experienced.

We expect that the 1998 testing period will take place in the July-August time frame and that the collected data will be reduced in time for the issuance of a final report by November-December 1998.

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1. Joseph G. DeAngelo, PE, et.al., Meeting The Title 1 NOx Requirements A Comprehensive Approach, 1997 International Joint Power Generation & Exposition Conference, Dallas, Texas, November 1997

2. B.A. Folsom, NOx Control Using Micronized Coal Reburning, American Boiler Manufacturers Association, Rochester, New York, September 1997

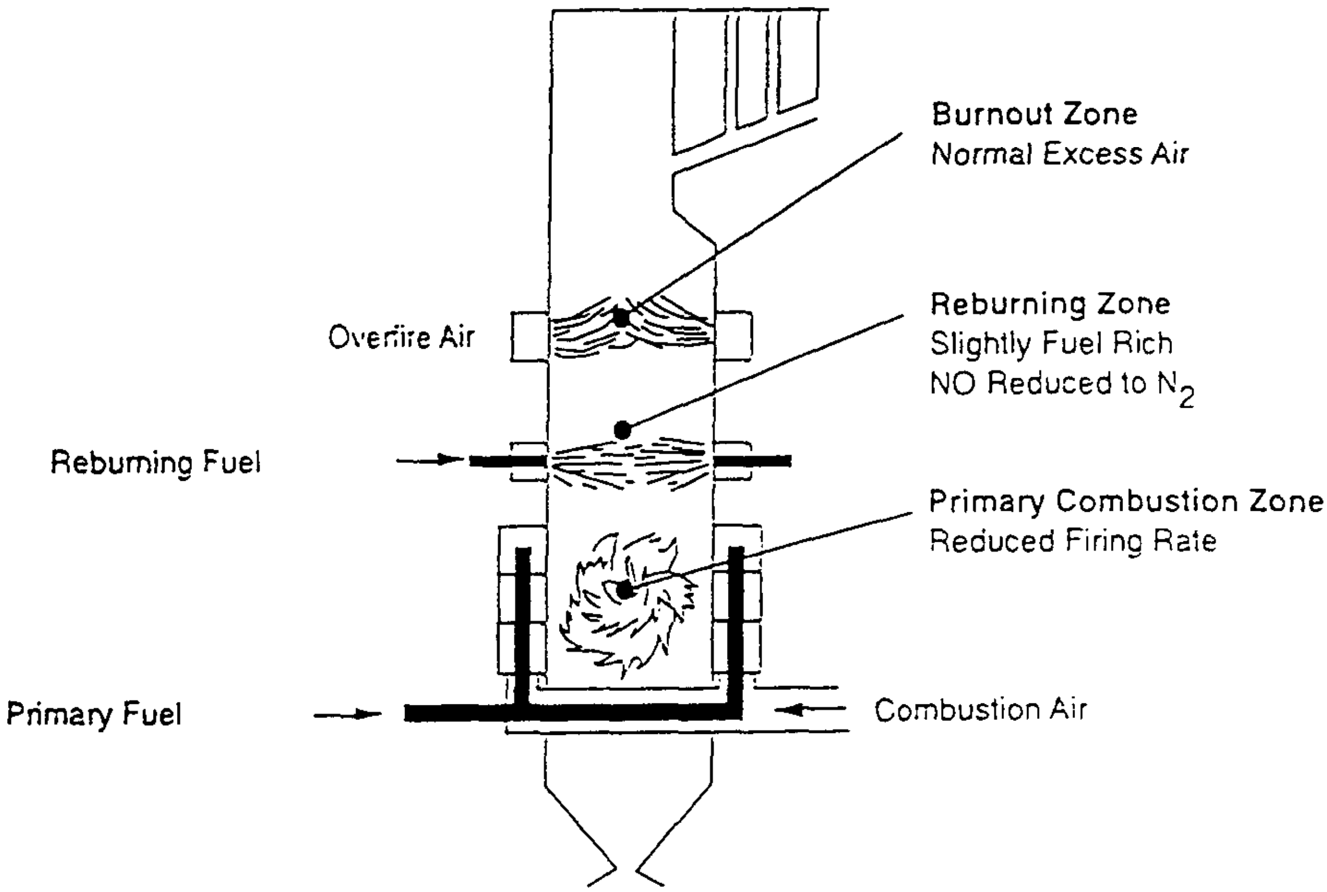


Figure 1. Application of a coal reburn to a utility boiler.

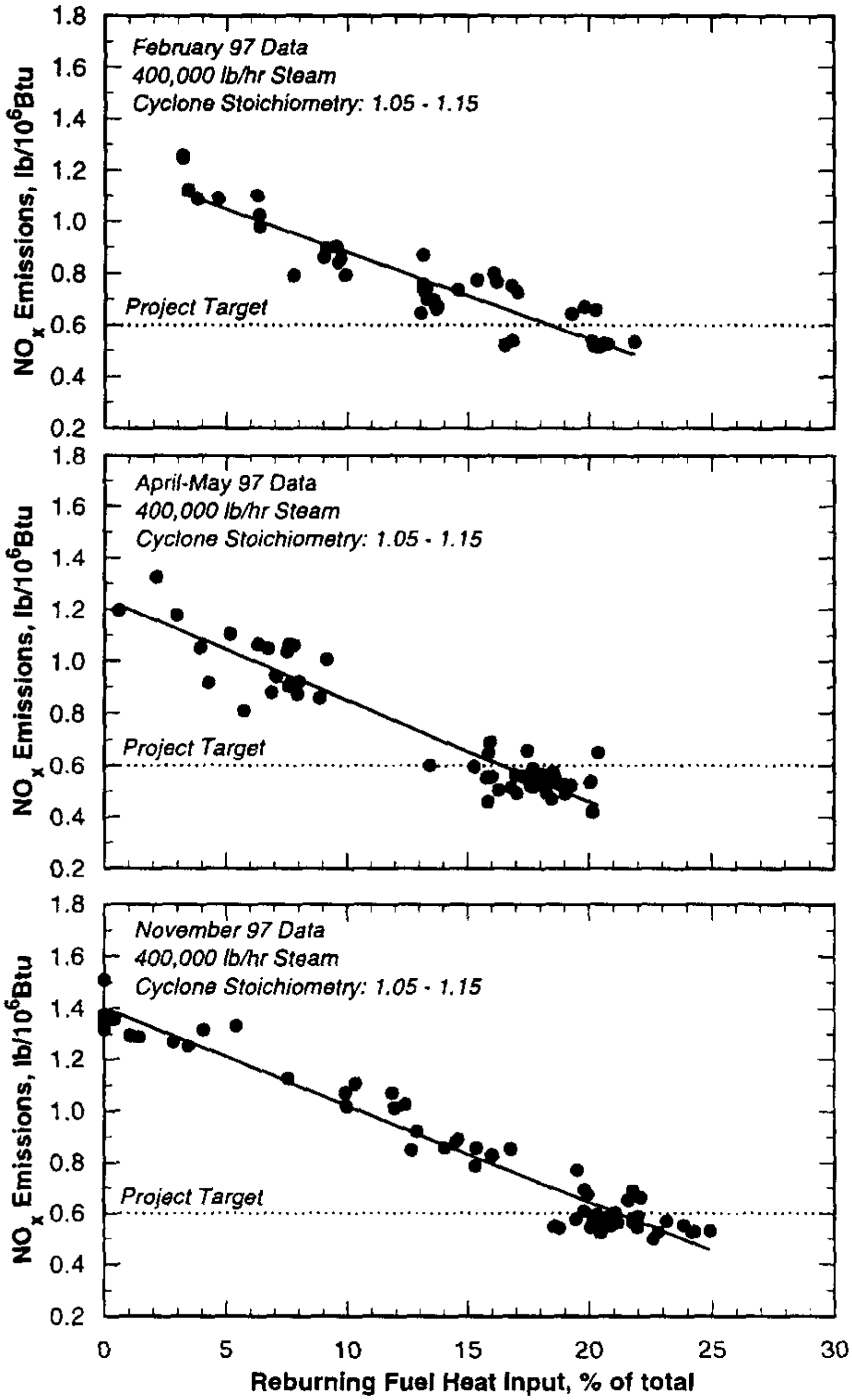


Figure 2. Impacts of reburn fuel on No_X emissions.

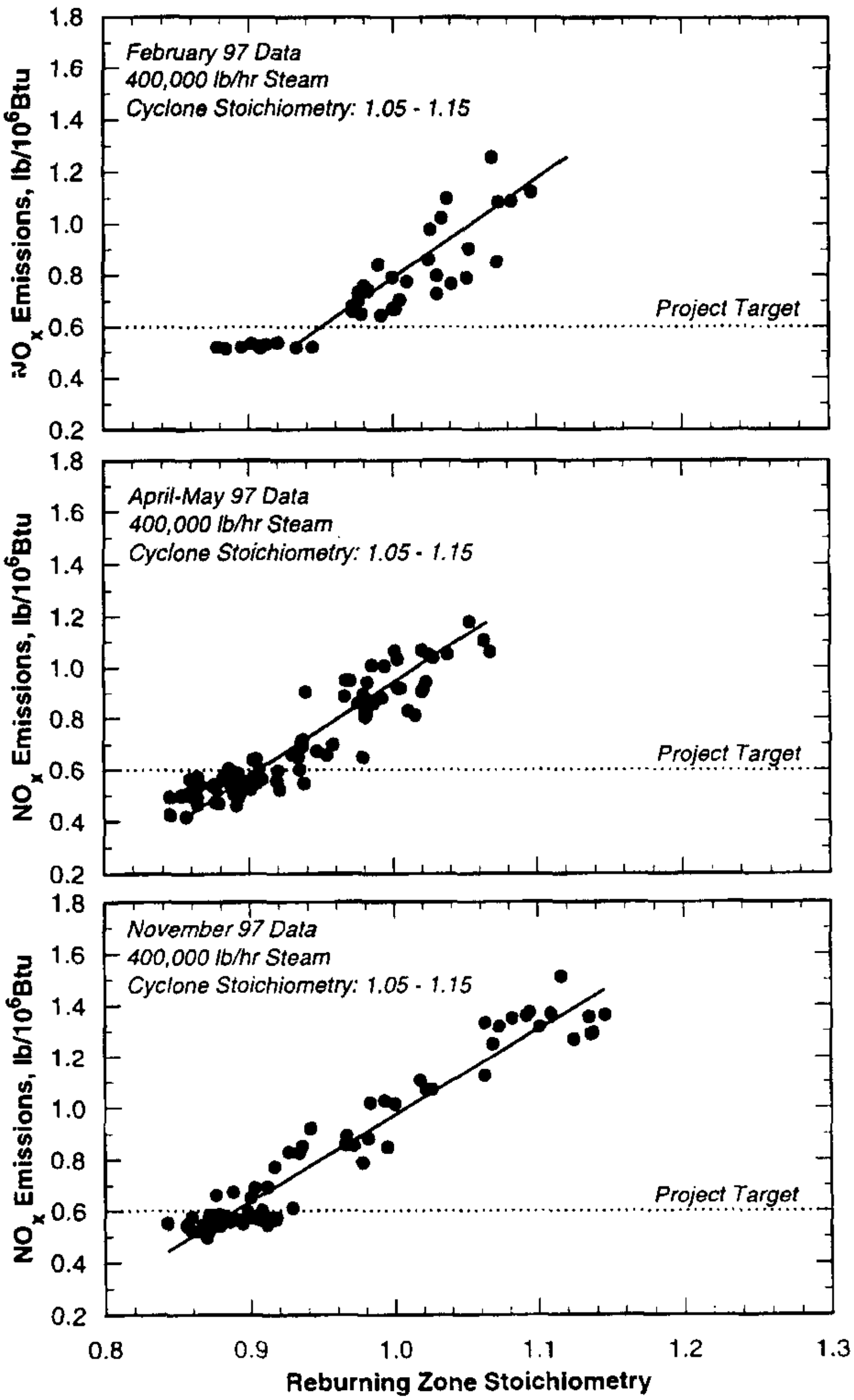


Figure 3. Impacts of reburning zone stoichiometry in NO_X emissions.

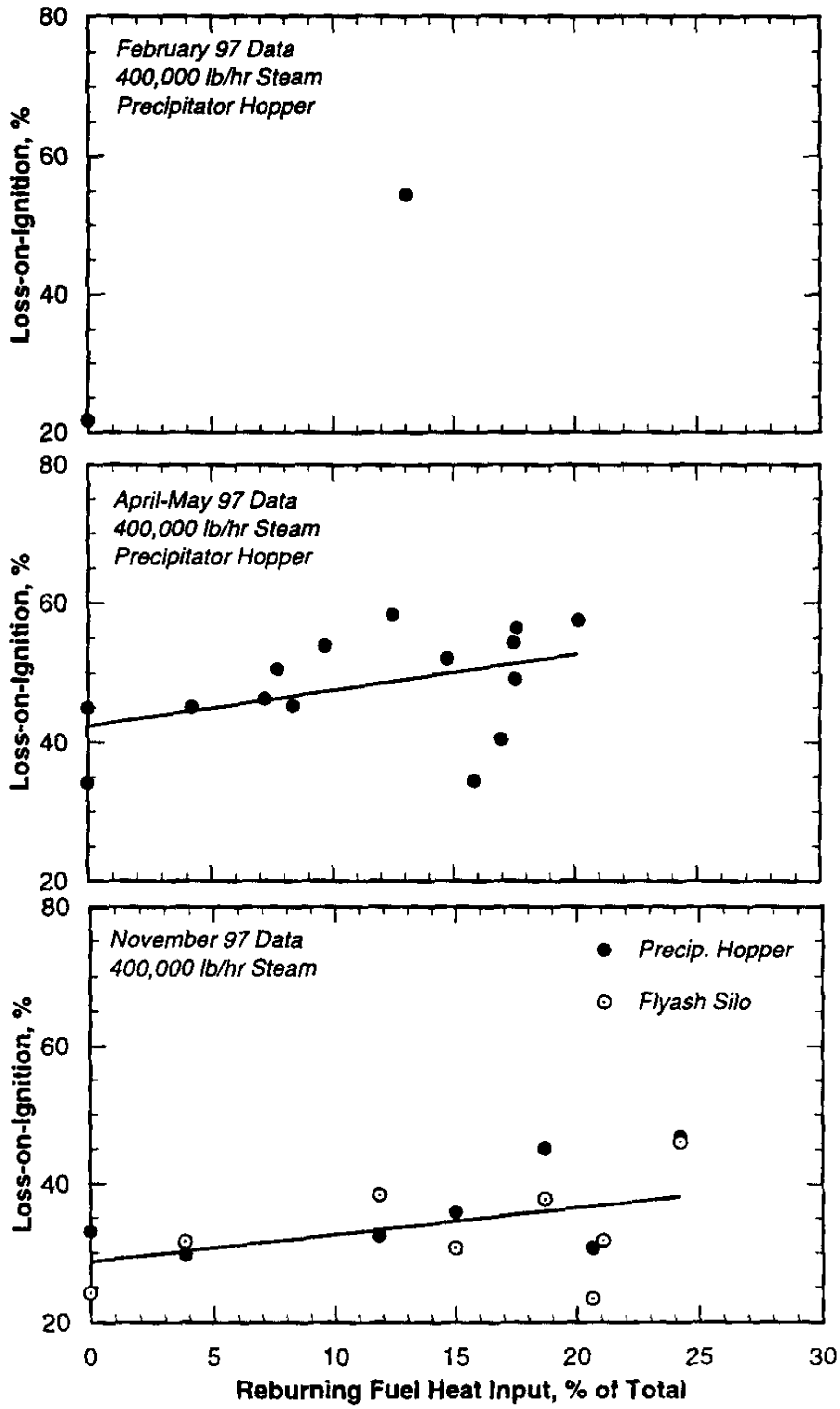


Figure 4. Impacts of reburning fuel on loss-on-ignition.

Figure 5 - Effect of SOFA Tilt

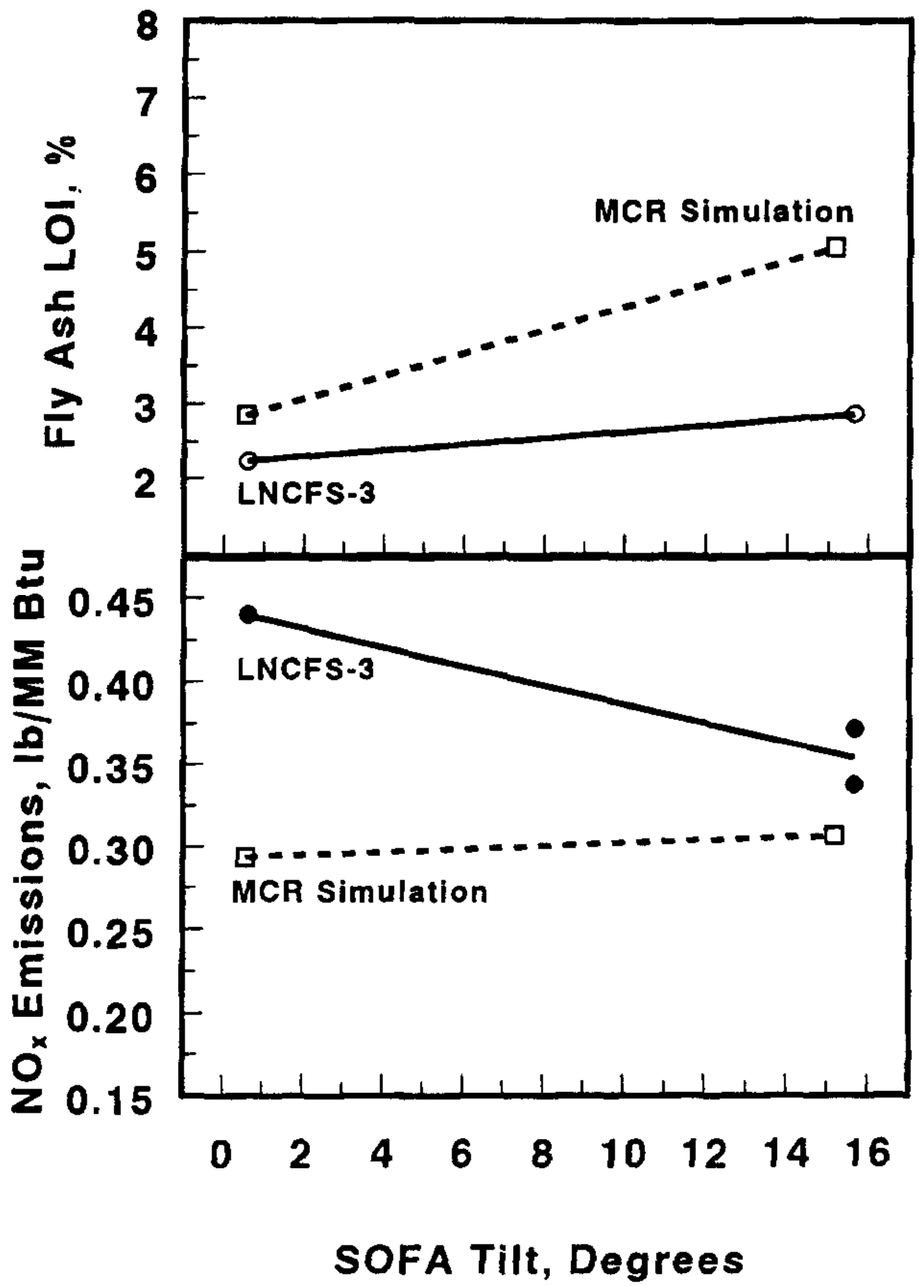


Figure 6 - Effect of Reburn Fuel Fineness

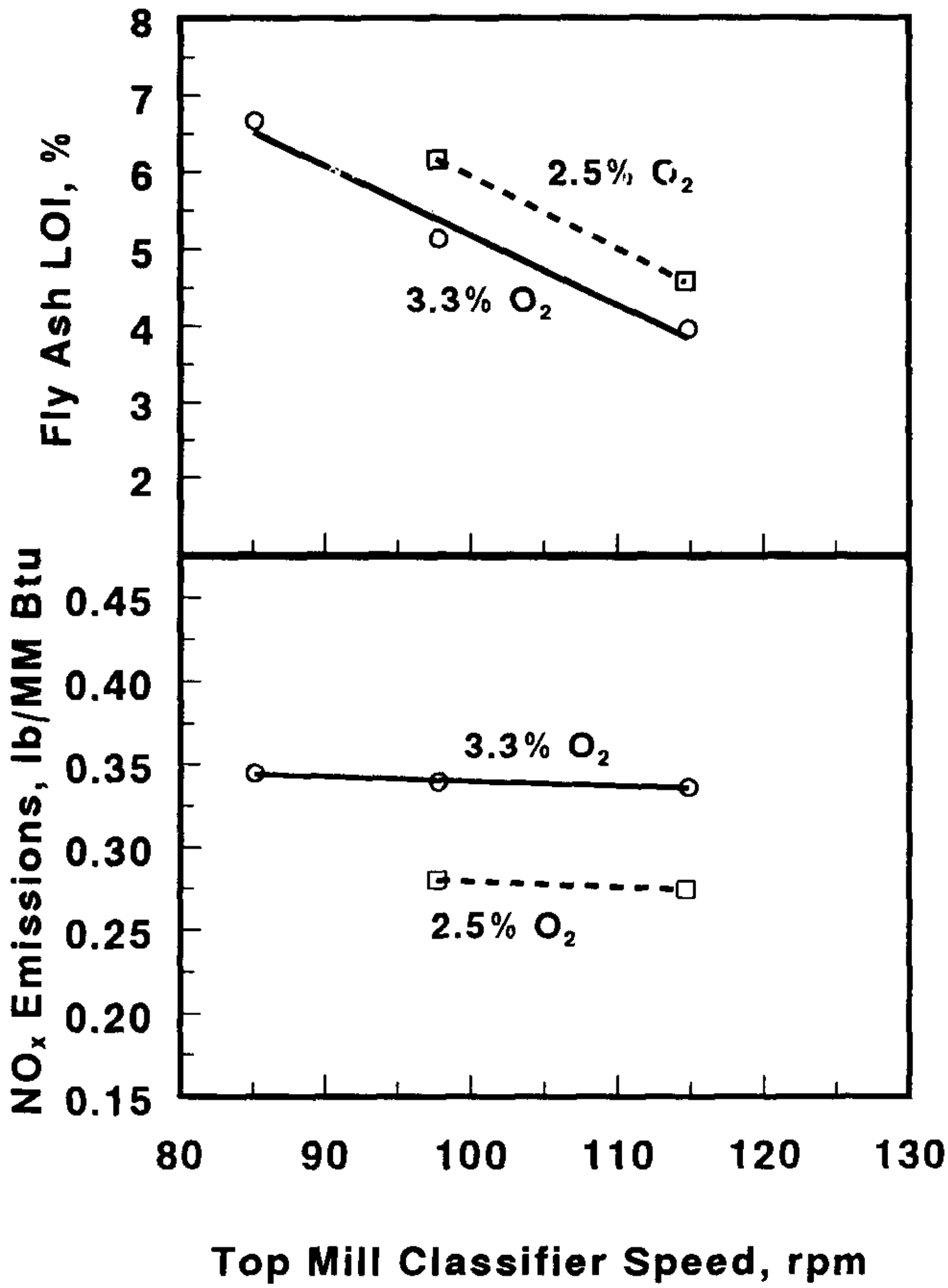


Figure 7 - Effect of Reburn Fuel Flow

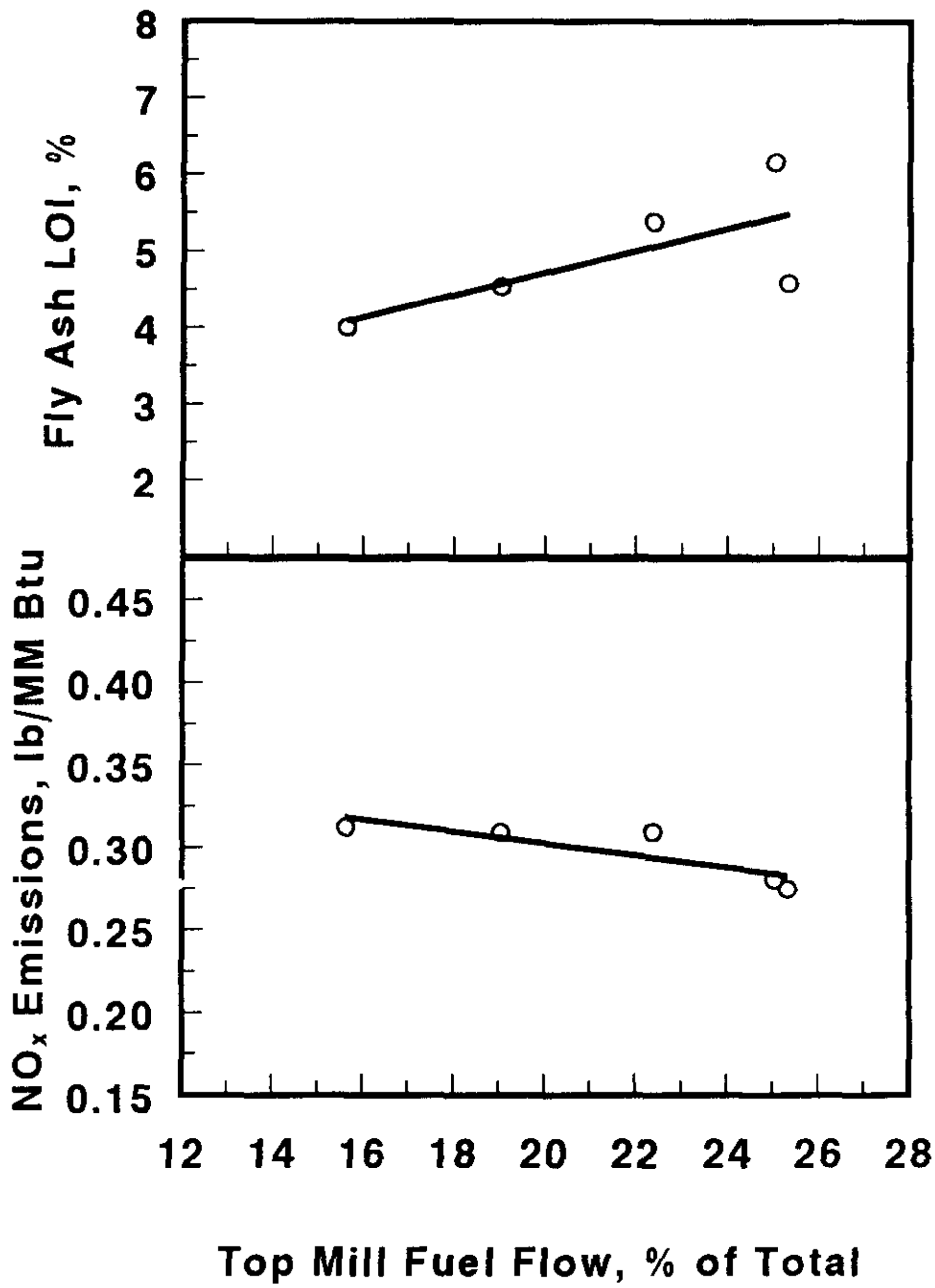


Figure 8 - Effect of Primary Air Flow

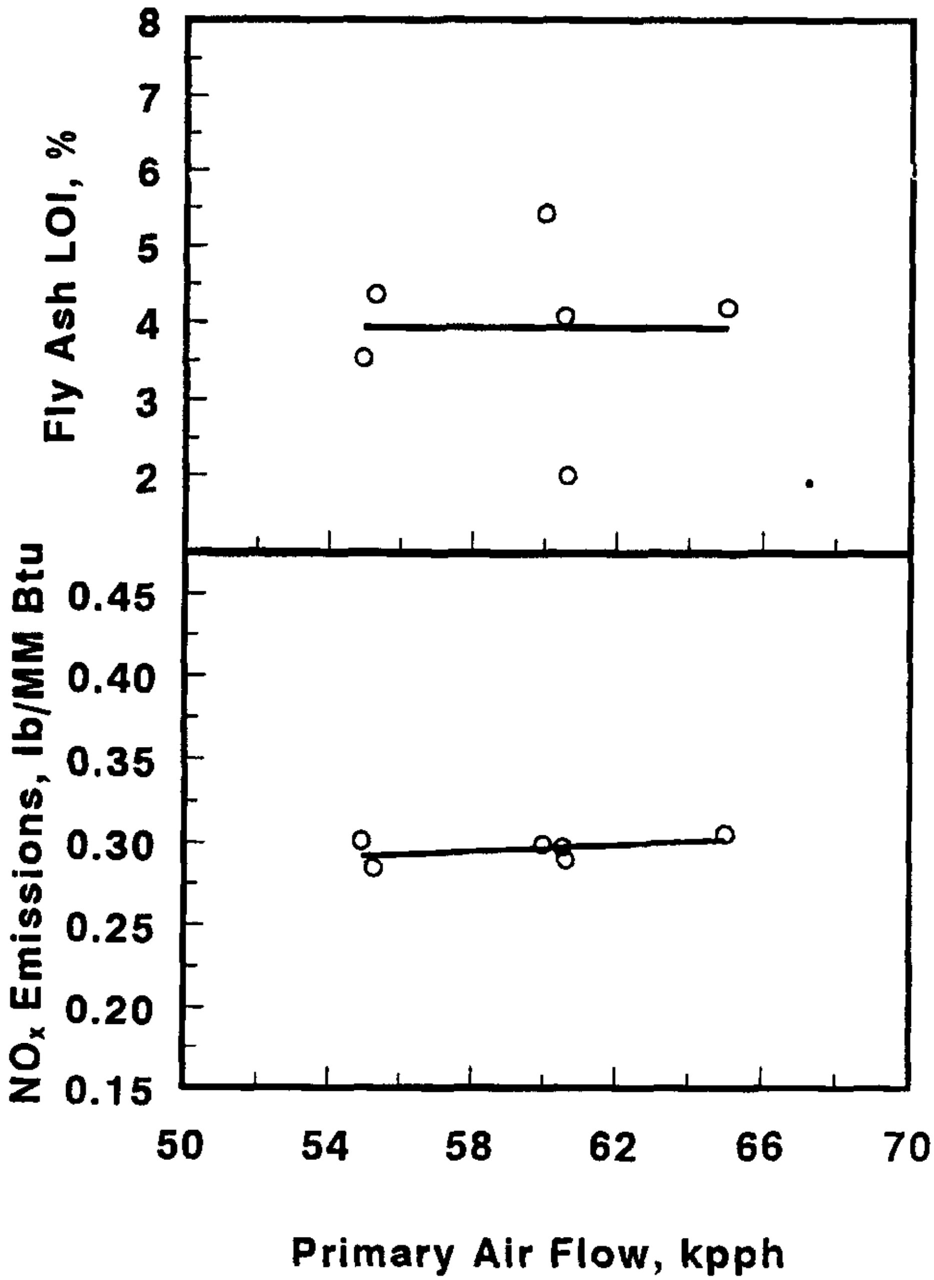


Figure 9 - Effect of Excess Air

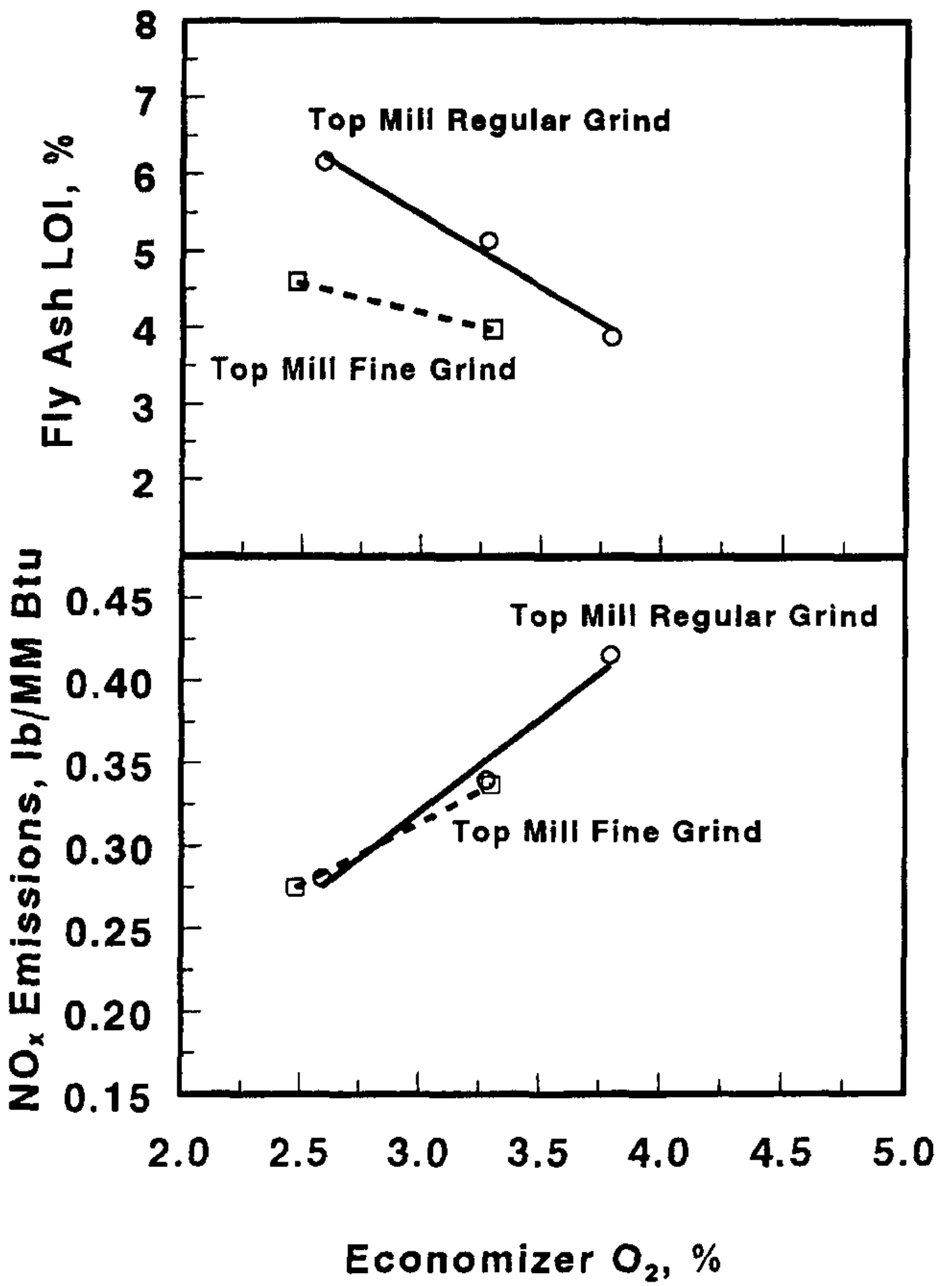
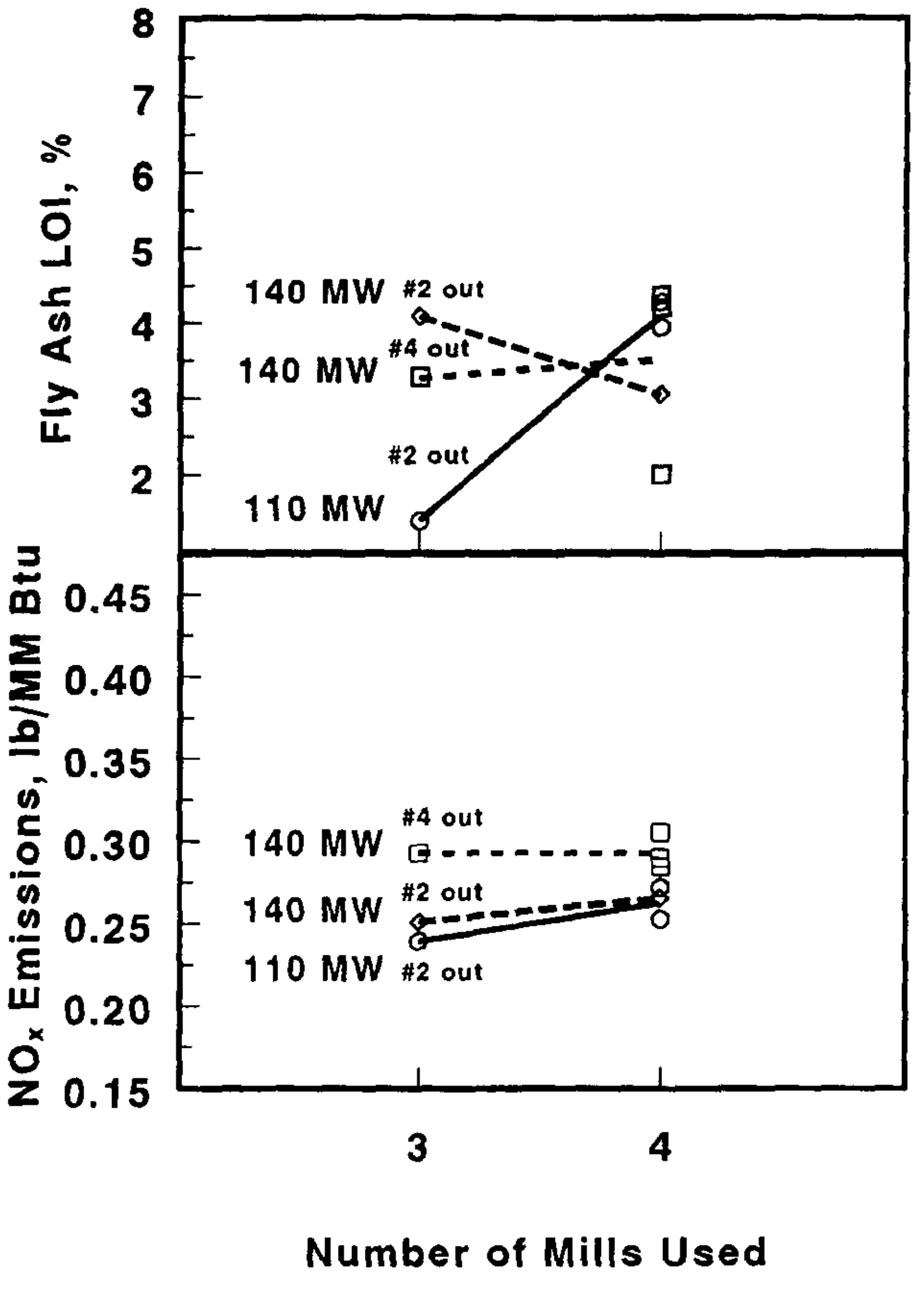


Figure 10 - Effect of Mill Pattern



COMBUSTION OPTIMIZATION USING GNOCIS™

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ABSTRACT

The Generic NO_x Control Intelligent System (GNOCIS) is an on-line enhancement to digital control systems and plant information systems targeted at improving power plant performance. The GNOCIS methodology utilizes a neural network model of the boiler combustion process and when applicable, other plant processes. The software applies an optimizing procedure to identify the best setpoints for the plant, which are implemented automatically without operator intervention (closed-loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open-loop). An overview of the GNOCIS technology is presented along with implementation issues and results from several sites.

I. INTRODUCTION

Deregulation of the industry has forced electric utilities to improve operating efficiencies of their units in an effort to reduce overall operating cost and become more competitive. Also, passage of the 1990 Clean Air Act Amendments has challenged U.S. electric utilities to reduce nitrogen oxide (NOx) emissions and to maintain these low emission rates during day-to-day operation. Boiler efficiency, fly ash carbon-in-ash (CIA or LOI), and NOx emissions are strongly influenced by a number of controllable and non-controllable operating parameters. Due to the combustion complexity and high coupling of a number of important process parameters associated with boiler combustion — especially for pulverized-coal-fired units — it is difficult to obtain an optimum or even acceptable operating point [EPRI, 1993]. When one operating parameter is improved, another is usually adversely affected. Therefore, continuous delicate balancing is needed to maintain the optimum over a wide operating range and for extended periods. The difficulty in optimization is compounded on units with low NOx combustion technologies installed. Original GNOCIS development was funded by the Electric Power Research Institute, PowerGen, Radian International, Southern Company, U.K. Department of Trade and Industry, and U. S. Department of Energy.[1]

II. DESCRIPTION OF GNOCIS

GNOCIS™ (Generic NOx Control Intelligent System) is an enhancement to digital control systems (DCS) targeted at improving utility boiler efficiency and reducing emissions. GNOCIS is designed to operate on units burning gas, oil, or coal and is available for all combustion firing geometries. The major elements of GNOCIS are shown in Figure 1 and are described below.

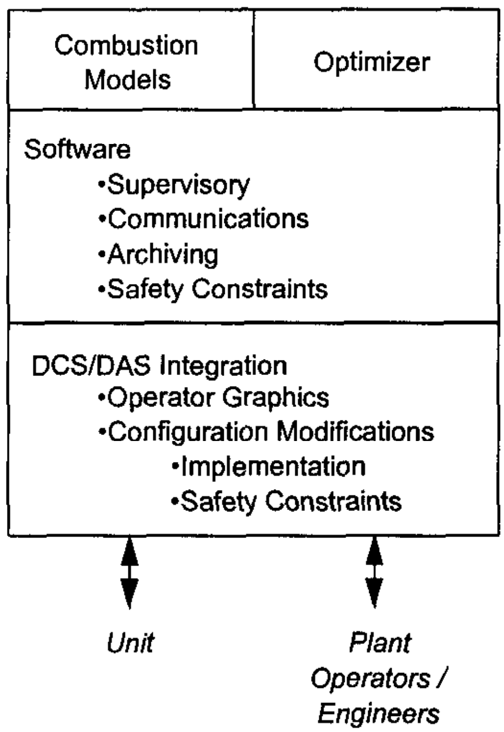

Figure 1. Major Elements of GNOCIS

Combustion Models

Modeling of the furnace is a critical element of GNOCIS. Since all optimization techniques make use of models (either local or global) of the process in developing recommendations, the veracity of the process model is highly important for the success of the optimization. GNOCIS utilizes neural networks for the combustion model [Beale, 1990][NeuralWare, 1993].

The combustion models are usually developed in two steps. The first step is the development of predictive models of the combustion process. Given the combustion process, predictive models are created using a subset of the measurable inputs and outputs of the process. The inputs may

[1] Research sponsored in part by the U.S. Department of Energy's Federal Energy Technology Center, under contract DE-FC22-94PC94253 with Southern Company Services, P. O. Box 2625, Birmingham, AL 35202.

consist of both controllable parameters (such as valve positions) and non-controllable parameters (such as ambient temperature or fuel quality).

Although predictive models are useful tools, what is required in GNOCIS are control models. A predictive model is designed to predict outputs given a set of inputs, but a control model must be designed to work in reverse — to predict inputs given a set of desired outputs. To predict the inputs effectively, a more complex structure is more appropriate. This structure is necessary since not all important inputs to the combustion model are controllable, and if controllable, they may not be independent. A critical element of the control model design is the selection and assignment of the various inputs to the controllable (or manipulated), non-controllable, and dependent classes. In many cases the partitioning is non-intuitive. Also, consideration must be given to the accessibility of the parameter within the DCS in a closed-loop installation or the ability of the operator to manipulate the control variables in an open-loop installation.

The flexibility of the modeling approach utilized in GNOCIS permits rapid development and modification of the combustion models. Although process variables utilized are very boiler dependent, variables that have been modeled include NOx, CO, opacity, LOI, boiler efficiency, heat rate, and furnace temperatures.

Optimizer

Optimization is the process by which a performance index is minimized (or equivalently, maximized) by the manipulation of one or more independent variables for which the performance index is a function [Dixon, 1972][Press, 1988]. GNOCIS utilizes a general, non-linear constrained optimizer with capabilities to handle disjoint feasible regions (i.e., possible solutions to the optimization are non-contiguous). The latter feature enables GNOCIS to make recommendations concerning operating conditions such as whether a mill should be removed or placed into service. Several factors were considered in this selection:

- GNOCIS is designed to be part of a supervisory control structure.
- The combustion process is generally highly non-linear.
- Constraints are needed for inputs, outputs, and derived functions.

A "typical" optimization scenario that can be readily configured in GNOCIS may be stated as shown in the box to the right. Further constraints could also be placed on the control variables such that only certain mills are to be considered in the optimization. Also, plant staff can easily change the goals through the operator screens.

Typical Optimization Scenario
Maximize boiler efficiency While {Maintaining NOx below 0.45 lb/Mbtu Maintaining LOI below 5 percent } Using {Mill biasing Excess oxygen Overfire airflow }

Digital Control System / Data Acquisition System Integration

GNOCIS is designed to be either integrated with a DCS, providing closed-loop optimization, or as an open-loop advisory system interfaced with a DCS or data acquisition system (DAS). Plant data is collected via a DCS or DAS and passed on to the GNOCIS host platform. Recommendations are then conveyed to the operator either through recommendation screens on the DCS/DAS or screens built in the GNOCIS host platform. The operator can then implement the recommendations, either manually or through the DCS. A closed-loop implementation is shown in Figure 2. In this configuration, GNOCIS gathers unit operating data via the DCS, and calculates the optimum setpoints. The optimum setpoints can be implemented by the operator or automatically by the DCS.

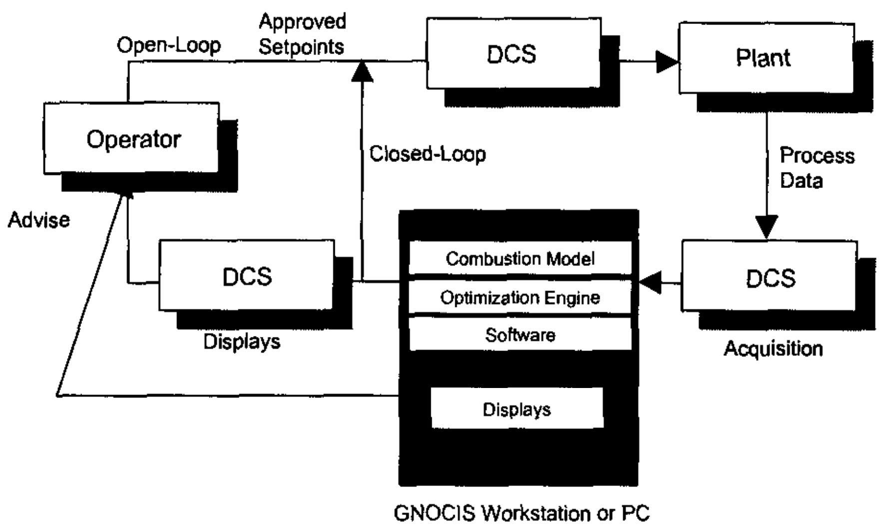

Figure 2. GNOCIS Implementation Structure

The recommendations provided by GNOCIS, whether open- or closed-loop, are supervisory in nature and are ideally implemented via the DCS. Therefore, many facets of a GNOCIS implementation are involved with the modification and upgrade of the DCS to implement the recommendations.

Operator Graphics

The operator displays are the principal interface to GNOCIS. These displays (1) convey to the operator the recommendations and predicted benefits and (2) allow the operator flexibility in setting constraints. An example of a GNOCIS operator screen is shown in Figure 3. As shown, the operator is presented with the current operating conditions and two sets of recommendations and predictions. One set corresponds to the current mills-in-service operating condition. If accepted, the operator can either implement the recommendations by individually setting the manipulated parameters to the targets or have the DCS automatically implement the recommendations (*Implement Recommendations*).

When *clamped*, the independent parameter is assumed to be unavailable for optimization purposes and is set to the current operating condition. The optimization is then performed with the remaining parameters. The operator can remove or add parameters from the optimization by using this screen (*Clamped / Free).*

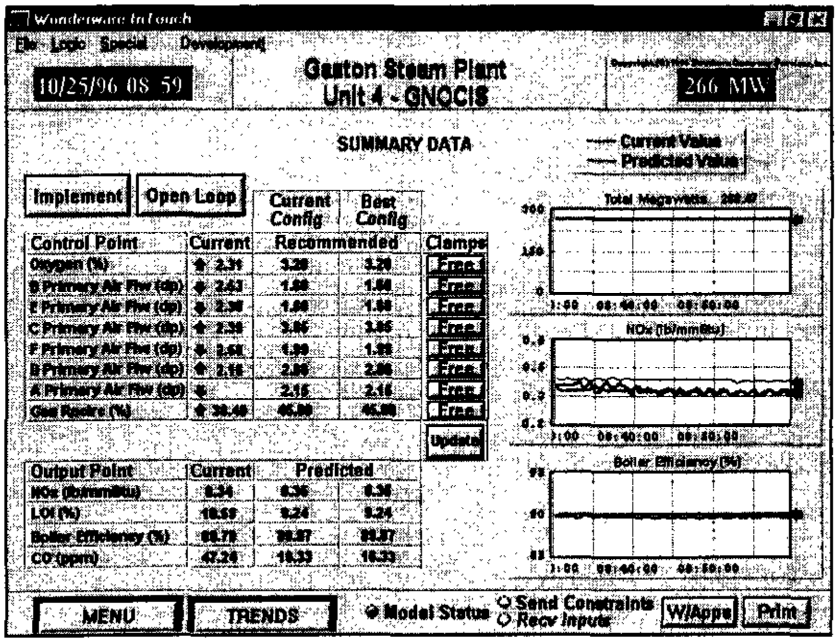

Figure 3. Example of GNOCIS Summary Screen

Since in many instances the mill selection can affect performance and emissions, it is important to provide recommendations concerning the mills in service. However, due to many externalities unmeasurable by the DCS or best judged by the operator, the mill configuration should not be automatically implemented. As a compromise, another set of recommendations is provided as to the optimum mills in service and the performance/emissions benefits. Given the predicted improvement and the current state of the plant, the operator can decide whether it is of overall advantage to change the mills in service. Closed-loop mode, if implemented, can be toggled with *Open Loop* by selecting the *Close Loop / Open Loop* button from this screen.

As mentioned earlier, the constraints and objective function implementation in GNOCIS is very flexible. A subset of this functionality is accessible via an operator graphic. High and low limits can be placed on both the controllable parameters (manipulated variables) and outputs. Hard constraints (cannot be violated) are used for the former, whereas soft constraints (can be violated but with a penalty applied to the objective function) are used for the latter.

Configuration Modifications

In order to obtain the full benefits of GNOCIS, modifications must usually be made to the DCS configuration, particularly for closed-loop implementations. However, whether open- or closed-loop, GNOCIS recommendations are considered supervisory in nature, and in most cases, setpoints or deviations from design curves are recommended. The level of complexity of the modifications is dependent on the desired integration of GNOCIS into the DCS and falls into three broad categories: addition of I/O blocks, implementation of GNOCIS recommendations, and validity checking (Table 1).

Table 1. Summary of DCS Configuration Modifications

	Open-Loop		
	Operator Implemented	DCS Implemented	Closed-Loop
Addition of I/O Blocks	✓	✓	✓
Implementation of GNOCIS Recommendations	n/a	✓	✓
Validity Checking	n/a	n/a	✓

III. PROJECTS UNDERWAY

GNOCIS projects are underway at a number of units (Table 2). These units represent a wide variety of generation capability, firing configuration, and fuel types. Implementation issues and results from several of these sites are discussed in the following paragraphs.

Table 2. GNOCIS Installations Underway or Planned

Unit	Type	Fuel	Capacity (MW)
Kingsnorth 1	T	C,O	500
Gaston 4	W	C	270
Hammond 4	W	C	500
Kingsnorth 3	T	C,O	500
Cheswick 1	T	C,G	570
Wansley 1	T	C	865
Branch 3	Cell	C	480
Gaston 3	W	C	270
Kingston	T	C	190
Ferrybridge	W	C	500
McDonough 1&2	T	C/G	500
Fiddlers Ferry	T	C	500
Gorgas 10	T	C	700
Others			2150
Generation Base			8495

Type: T - Tangential -Fired; W - Wall-Fired
Fuel: C - Coal; O - Oil; G - Natural Gas

Kingsnorth Units 1 and 3

Kingsnorth Units 1 and 3, owned and operated by PowerGen, plc, are 500 MW units capable of reaching full load on either coal or residual fuel oil. Each unit is fitted with five mills, all of which are required to achieve full load on most (but not all) of the coals supplied to the station. Each furnace is fitted with a low NOx concentric firing system with separated overfire air. The unit is equipped with the CEGB developed CUTLASS digital control system. The coal mill control system uses mill feeder speeds as the prime control variables. In fully automatic mode, the goal of the control system is to match the feeder speeds of all mills in service, while maintaining the required load. One or more mills may be put on manual control where the feeder speed is fixed at a constant value and the remaining feeder speeds are again varied to meet the required load. The station has a NOx emission limit of 390 ppm (at 6% O_2). These emissions are not, however, subject to statutory continuous monitoring. Along with Gaston 4, Kingsnorth Unit 1 was a developmental site for GNOCIS.

GNOCIS was used to optimize NOx emissions and carbon-in-ash. Controllable parameters used for the optimization include feeder speeds (5), excess oxygen, and burner tilt. The recommended control settings that GNOCIS produces are passed back to the DCS, where they are conveyed to the operator via a display on the unit control panel (open-loop).

Numerous tests were conducted during the course of the development at this site. For example, for several tests GNOCIS was instructed to produce the best set of inputs that would keep NOx below its statutory limit and minimize carbon-in-ash. Figure 4 shows the result of one such trial, where a 4 percentage point reduction in carbon-in-ash was obtained at the small cost of a 10 ppm rise in NOx (but still well below the statutory limit of 390 ppm). To demonstrate GNOCIS' flexibility and to show that it could cope with other objective functions, a further test was undertaken. In this, the optimizer attempted to reduce NOx while containing any increase in carbon-in-ash. Figure 4 shows the success of this test: NOx fell from 350 ppm to 325 ppm with barely any change in the carbon-in-ash, which stayed at 12 percent.

GNOCIS is currently available to the operators on both Unit 1 and 3 and is used as needed to provide operational recommendations.

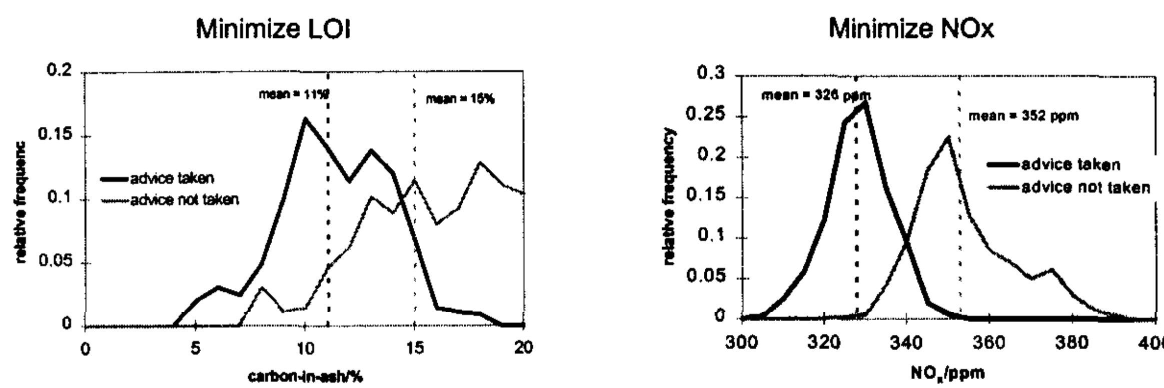

Figure 4. Example Results from Kingsnorth

Gaston 4

Alabama Power's Gaston Unit 4, along with Kingsnorth Unit 1, was a development site for GNOCIS. Gaston Unit 4 is a 270 MW pulverized-coal unit. The Babcock and Wilcox (B&W) opposed-wall-fired boiler is equipped with eighteen B&W XCL low NOx burners and six B&W EL-76 ball and race mills. The boiler control system for Gaston Unit 4 is a Leeds and Northrup MAX 1000 distributed digital control system. GNOCIS is designed to operate in either closed- or open-loop mode at this site. Manipulated variables for this installation include excess oxygen and mill flows (6) while the parameters being optimized are NOx, boiler efficiency, and fly ash LOI.

Open- and closed-loop testing have been conducted. Open-loop tests conducted as part of the developmental program indicated that GNOCIS was able to improve boiler efficiency by approximately 0.5 percentage points and reduce LOI by approximately 3 percentage points when this was the objective. When used to minimize NOx, reductions of nearly 15 percent were obtained (Figure 5). Following completion of the formal test developmental program, the site conducted some intermediate load tests during December 1996, the results of which are shown in Figure 5. During spring 1998, GNOCIS was being upgraded to reflect the most recent version of the software. Plans are to return to closed-loop operation following this upgrade.

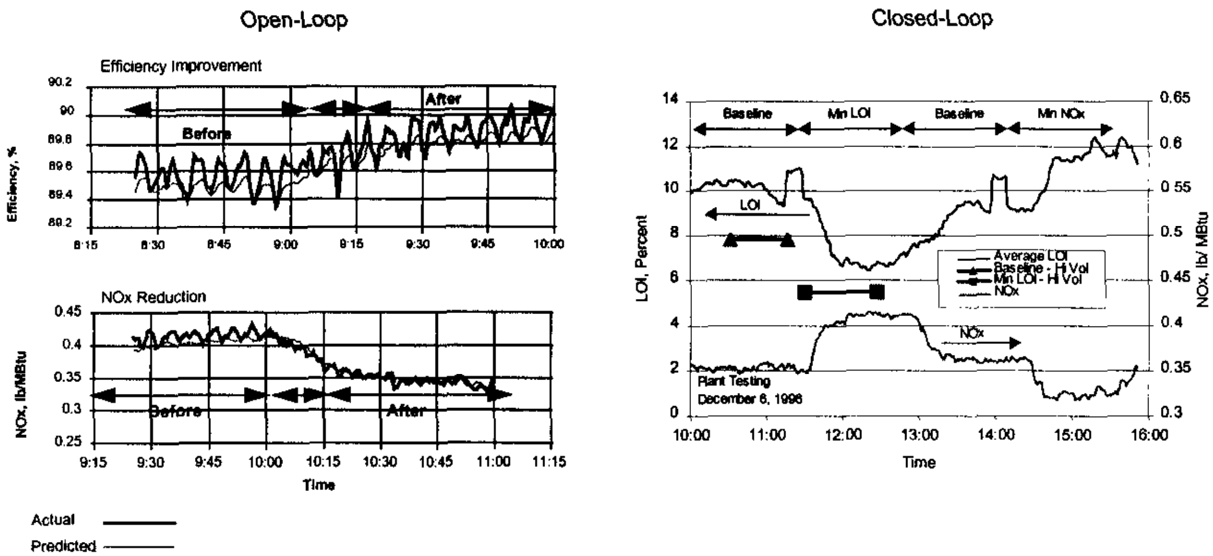

Figure 5. GNOCIS Testing at Gaston 4

Hammond 4

The GNOCIS project at Georgia Power's Plant Hammond was undertaken as part of a U.S. Department of Energy Innovative Clean Coal Technology program being conducted at this site.[2] The overall project provides a stepwise evaluation of the following NOx reduction technologies: Advanced overfire air (AOFA), low NOx burners (LNB), LNB with AOFA, and optimization strategies [SCS, 1998]. GNOCIS is being demonstrated as the advanced control/optimization technology. Hammond Unit 4 is a Foster Wheeler Energy Corporation (FWEC) opposed wall-fired boiler, rated at 500 MW. Six B&W MPS 75 mills supply pulverized eastern bituminous coal to twenty-four FWEC Controlled Flow/Split Flame (CF/SF) low NOx burners. The unit is also equipped with a FWEC designed Advanced Overfire Air (AOFA) system. The boiler control system for Hammond 4 is a Foxboro I/A distributed digital control system. The GNOCIS system is designed for either closed- or open-loop operation. Manipulated variables for this installation include excess oxygen, mill flows (6), and overfire air damper positions (4) while the parameters being optimized are NOx, boiler efficiency, and fly ash LOI.

GNOCIS installation was completed during first quarter 1996 after which testing began.

[2] Demonstration sponsored in part by the U.S. Department of Energy's Federal Energy Technology Center, under contract DE-FC22-90PC89651 with Southern Company Services, P. O. Box 2625, Birmingham, AL 35202.

Test 158 is a representative example (Figure 6) of the test conducted to date and provides some insight into the benefits of on-line optimization. This test was conducted with the unit off economic dispatch and at 480 MW. The purpose of the test was to evaluate GNOCIS performance in regards to boiler efficiency improvements as GNOCIS was made sequentially less constrained. As shown, nominal boiler efficiency was near 87.5 percent at the beginning of the testing and with sequential application of the GNOCIS recommendations, an efficiency of approximately 88.3 percent was attained. As can be seen, recommendations for excess oxygen, AOFA damper, and mill flows were implemented at approximately 11:15, 12:10, and 12:45, respectively. Although not shown, the recommended AOFA damper position is dependent on whether the mills are included in the optimization which is indicative of a non-linear process.

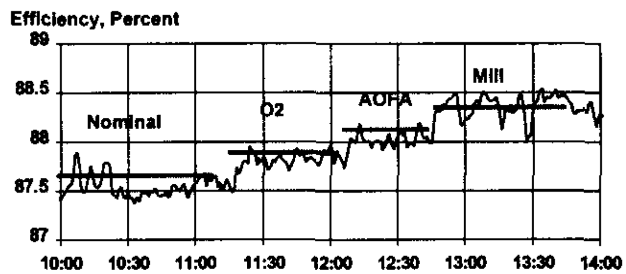

Figure 6. Hammond / Results of Test 158

Cheswick Unit 1

Duquense Light's Cheswick Station is a 570 MW coal-fired generating unit with also the capability to co-fire natural gas at up to about 20 percent of heat input. The tangential-fired unit is equipped with overfire air and low NOx burners. The unit has installed a LOI monitor and CO monitors in the boiler exit ducts. Cheswick fires a blend of coals (blend based on coal sulfur content) and is equipped with an on-line coal analyzer in the coal yard. The GNOCIS demonstration at Cheswick, which is an EPRI funded tailored collaboration project, has two objectives. These include NOx reduction and heat rate improvement. The GNOCIS models' outputs are NOx, heat rate, LOI, CO, and opacity. Manipulated variables include excess oxygen, warm-up gas flow, SOFA damper demands, and mill coal flows. Sensor validation models were developed for all of the model inputs. The sensor validation model is used to detect when a process sensor may be having problems and to substitute a value for use in the control model. The GNOCIS models run on a Westinghouse WDPF workstation with operator screens integrated into the DCS.

During November 1997, open- and closed-loop testing of GNOCIS was conducted at Cheswick. The open-loop testing was conducted in stages with implementation of each control variable's settings done at a time for "minimizing NOx" and then again for "minimizing heat rate." The results for the minimize NOx test is shown in Figure 7. For this test, NOx was reduced from about 0.43 lb/MBtu to about 0.39 lb/Mbtu, a 10% reduction. The impacts on the other variables are also shown in this figure. The closed-loop testing was conducted in "minimize NOx", "minimize heat rate", and "minimize NOx and heat rate." The results of the latter test are shown in Figure 8. During the two-hour period when GNOCIS was active, both NOx and heat rate were improved with NOx emissions decreasing by 10% while heat rate decreased by more than 1%.

Due to the process variation, these improvements are difficult to see from the charts. However, with a 90% confidence level, the true difference in the mean heat rate for the on and off periods is between 51 to 116 Btu/kWh. For NOx, the corresponding reduction is 0.012 to 0.02[illegible] lb/MBtu. GNOCIS is now running in closed loop mode at this site.

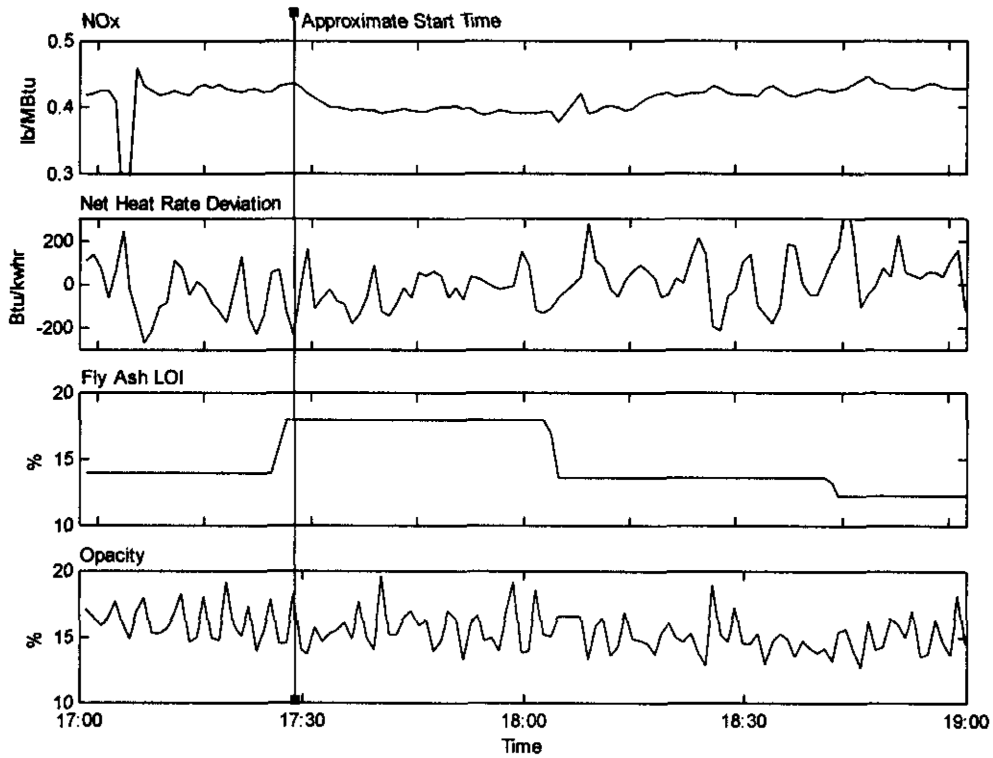

Figure 7. Cheswick / Minimize NOx / Open-Loop

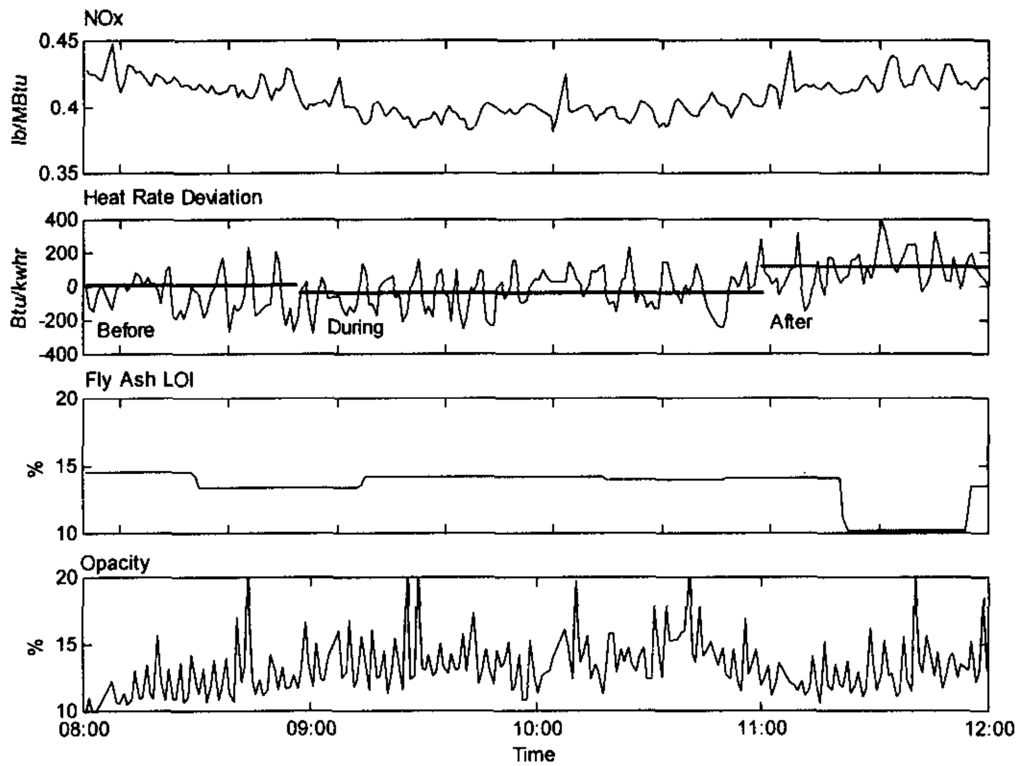

Figure 8. Cheswick / Minimize Heat Rate and NOx / Closed-Loop

Branch Unit 3

Georgia Power's Branch Unit 3 is a 480 MW coal-fired unit equipped with cell-burners. A Foxboro I/A DCS is used as the control system. Unit 3 shares a stack (and associated CEMS) with Unit 4. The GNOCIS models run on a Windows NT workstation that has been installed and integrated with the Foxboro DCS. Operator interface screens have been developed and are fully integrated into the DCS. The GNOCIS system is designed to operate in either open-loop or closed-loop mode. The outputs from the GNOCIS system at Branch 3 are NOx, LOI, and boiler efficiency. The manipulated variables are excess oxygen, feeder speeds (10), and primary air/fuel ratios (10). This GNOCIS installation incorporates data from both Units 3 and 4 so that the influence of Unit 4 operations on NOx emissions can be separated from those of Unit 3.

Several predictive and control models have been developed for this site. The results of one model are shown in Figure 9 through Figure 11. For this model, the inputs were the feeder speeds (10 total) and excess oxygen. The data shown represents approximately 60 hours (4000 records of data) of operation. The neural network models were trained on a separate 120 hours (8000 records) of data. As shown, the neural network models fairly accurately portrayed actual unit operation, especially for boiler efficiency. The error bars on this and subsequent figures represent the 5^{th} and 95^{th} percentile of data. This model may be used to determine optimum setpoints to maximize efficiency or minimize NOx emissions. For the former, an efficiency gain of 0.5% over the load range is predicted (Figure 10). For the latter, NOx emission reductions of around 0.1 lb/MBtu are predicted (Figure 11). Note that for both these scenarios, there is little impact on the other optimized variable. Also, the movements of the manipulated variables about the current value were rather restrictive: excess oxygen - ±0.5%; feeder speeds - ±5% and further improvement may be achieved if the bands were relaxed.

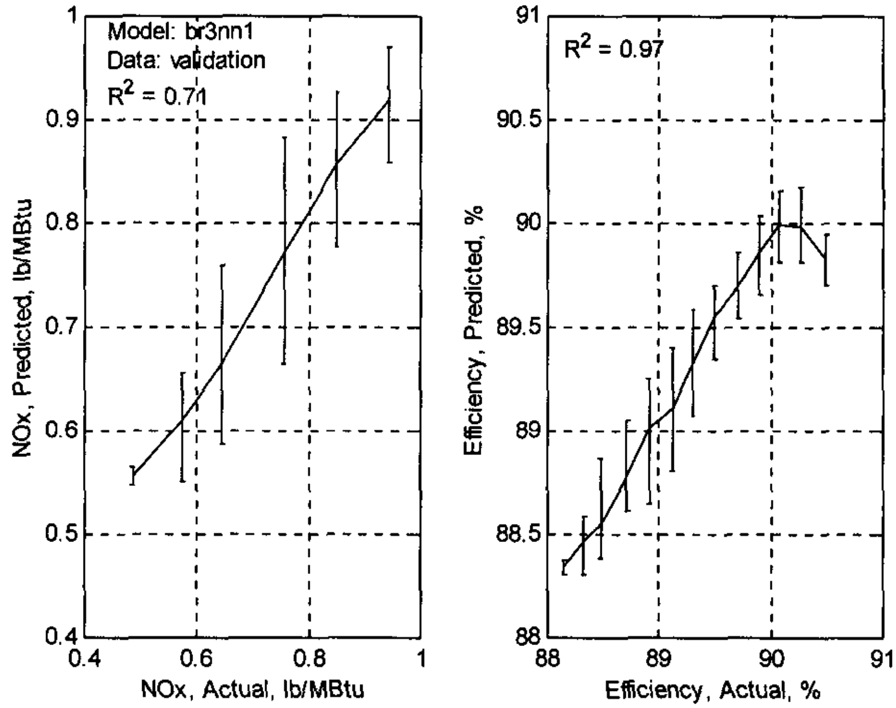

Figure 9. Branch / NO_x and Efficiency / Predicted vs. Actual

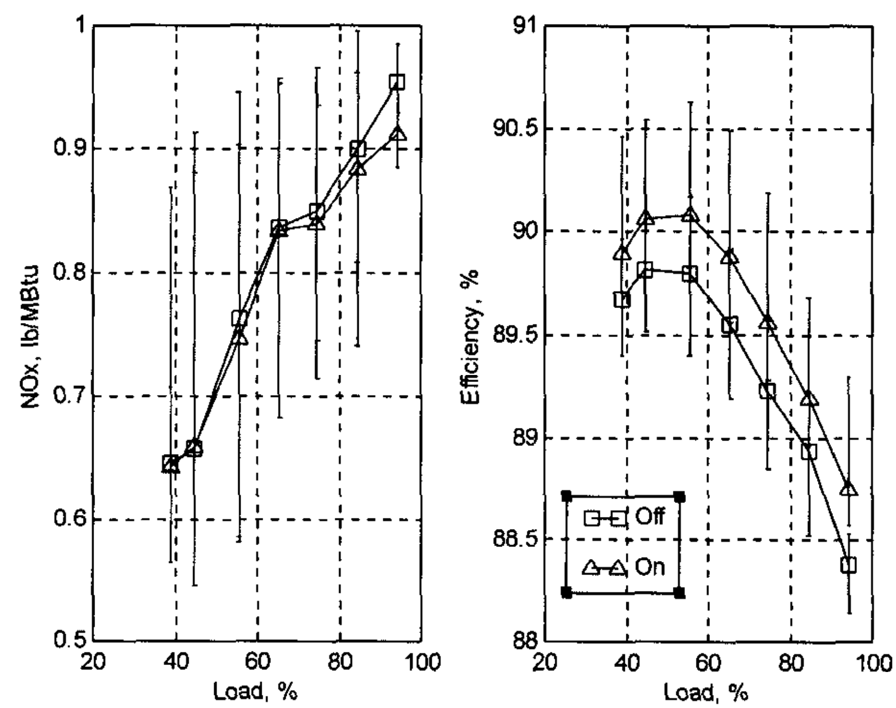

Figure 10. Branch / Maximize Efficiency / Predicted

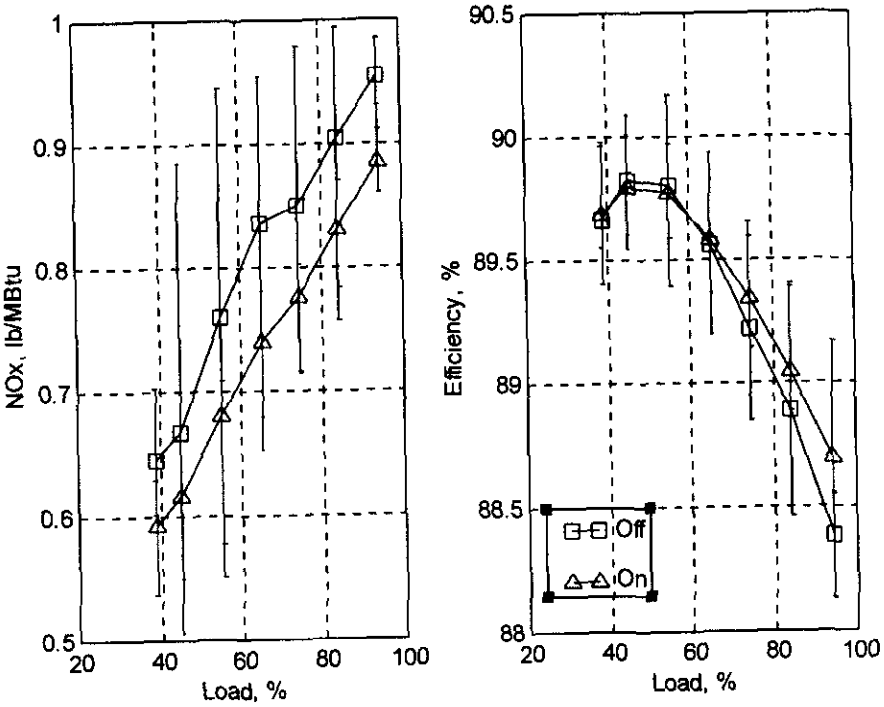

Figure 11. Branch / Minimize NOx / Predicted

The results shown above are based on model predictions and need to be verified by plant testing. However, the predicted values are representative of what has been observed at other sites.

The GNOCIS installation at Branch is now complete and plant operator training is planned for April 1998. Following this training, testing of the GNOCIS system is planned.

Montour Unit 2

PP&L's Montour Unit 2 is a CE tangential-fired once-through supercritical boiler burning pulverized bituminous coal. It has ABBCE LNCFS III low NOx burners installed. Six elevations of burners are fed pulverized coal from Raymond bowl mills. These mills are being upgraded with high efficiency exhausters, dynamic classifiers, and increased range mill airflow measurement instrumentation. Unit 2 is rated at 750 MW. The unit uses a MAX Control Systems MAX 1000 DCS for burner management, combustion control, and data acquisition functions. GNOCIS is now being installed on this unit for both open- and closed-loop operation and is scheduled for operation during summer 1998.

As part of the project, a feasibility study was conducted which included the development of prediction and control models. The results of one control model are shown in Figure 12. As shown, the model was a fairly faithful predictor of both NOx emissions and heat rate with an R^2 of 0.89 and 0.93 for NOx and heat rate, respectively.

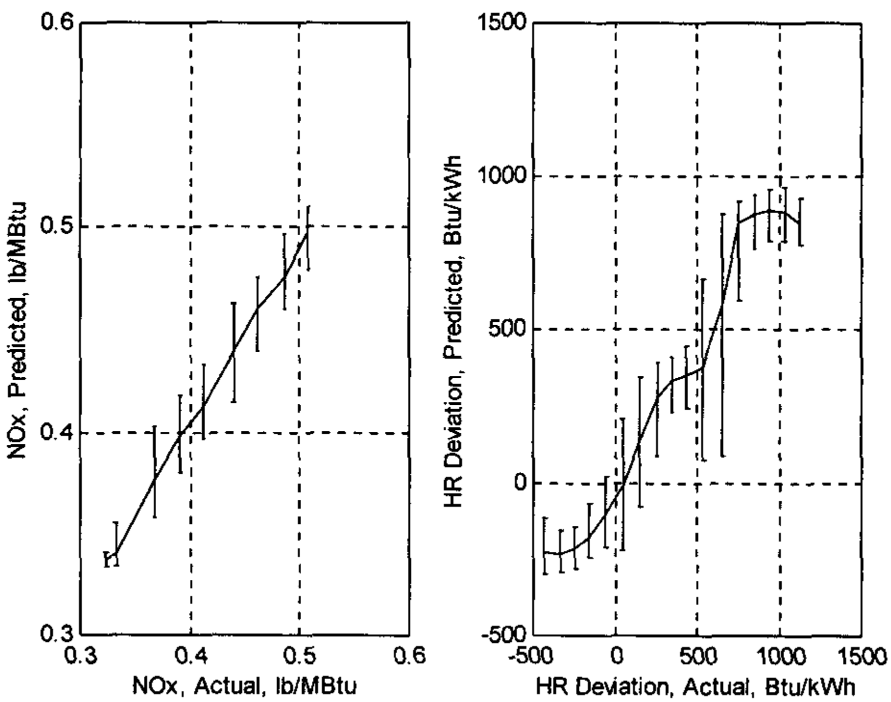

Figure 12. Montour / NO_x and Heat Rate / Predicted vs. Actual

Of course the goal of GNOCIS installation is to improve performance and not necessarily to predict performance. To this end, studies were conducted to investigate the potential gains if the

GNOCIS recommendations were followed. The first step in using the control model is to set limits on how far the model is allowed to change any of the control variables. For purposes of this exercise, typical values based on previous experience at other GNOCIS installations were used and were ±10% on the feeders, ±10°F for mill outlet temperatures, ±0.5% for excess oxygen, and ±10% for the SOFA damper demands. Another constraint implemented is that the sum of all of the feeder speeds must remain constant (that is, if one feeder speed is decreased then one or more other feeder speeds must be increased to offset it, so that the total coal flow to the boiler remains constant). Example results obtained when minimizing NOx and heat rate are shown in Figure 13. An average heat rate reduction of 147 Btu/kWh simultaneously with a 10% reduction in NOx emissions was predicted. Although promising, these results need to be confirmed by plant testing.

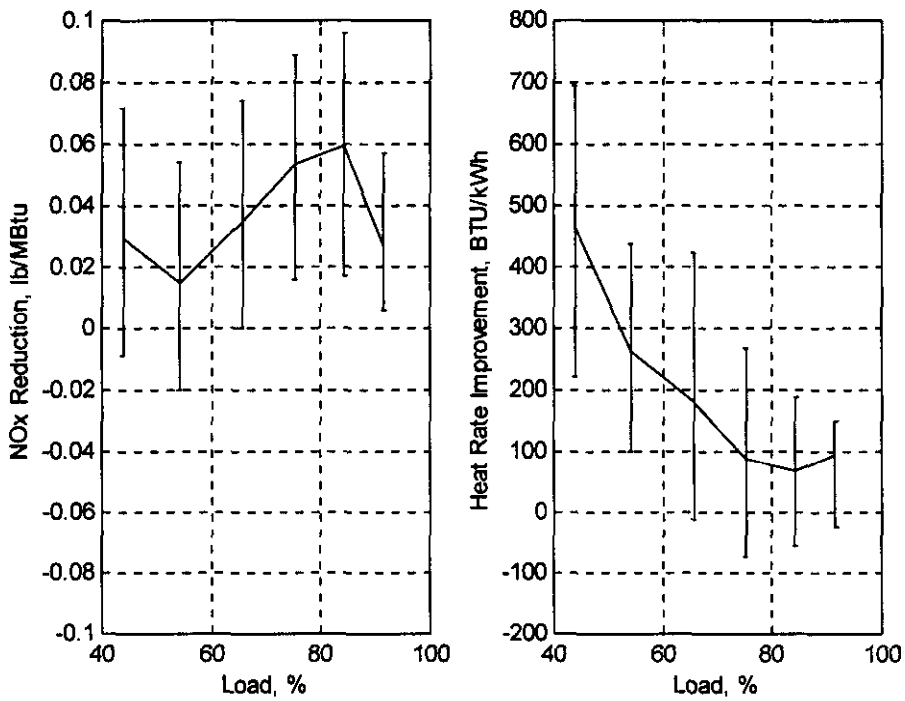

Figure 13. Montour / Optimizing NOx and Heat Rate / Predicted Performance

Kingston Unit 9

TVA's Kingston Unit 9 is a 190 MW Combustion Engineering tangential-fired, twin-furnace boiler. The unit has been retrofitted with a Foxboro I/A digital control system [Linkins, 1997]. GNOCIS was installed on this unit during a 10-week period during third quarter 1997. The system is designed to be operated in either open- or closed-loop mode. Manipulated variables include pulverizer speeds (6), auxiliary air damper positions (8), minimum excess oxygen (reheat side vs. superheat side), and excess oxygen differential (reheat side - superheat side). Optimized variables include net plant heat rate, superheat furnace NOx, and reheat furnace NOx. Acceptance testing was conducted during fourth quarter 1997. Plans are to report the results from these and subsequent tests at a later date.

Wansley Unit 1

Georgia Power's Plant Wansley Unit 1 is a 900 MW coal-fired generating unit with a tangential-fired boiler. A Foxboro DCS is used as the control system. An LOI monitor has been installed to allow on-line feedback with respect to the ash combustibles content. The important GNOCIS control variables that have been identified for this plant include oxygen, mill biasing, and SOFA damper positions. The outputs from the GNOCIS system at Wansley 1 are NOx, LOI, opacity, and boiler efficiency. The GNOCIS models run on a PC running Windows NT integrated with the Foxboro DCS. Operator interface screens are fully integrated into the DCS. The GNOCIS system has been installed to operate in either open-loop or closed-loop mode. Testing at this site is now in progress.

IV. SUMMARY

A summary of the projects and the results to date are as follows:

- GNOCIS has been successfully deployed in both open-loop advisory and close-loop supervisory modes.
- GNOCIS has been able to provide advice that reduced carbon-in-ash and improved boiler efficiency.
- GNOCIS provided advice that reduced NOx emissions.
- The advice GNOCIS makes is consistent with good engineering judgment.
- Several projects are underway which will further quantify the benefits and costs associated with GNOCIS.

V. ACKNOWLEDGMENTS

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MILLIKEN CLEAN COAL TECHNOLOGY DEMONSTRATION PROJECT

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ABSTRACT

The Milliken Clean Coal Demonstration Project is one of nine Clean Coal Projects selected for funding in Round 4 of the United States Department of Energy's Clean Coal Demonstration Program. The project provides a full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from a coal-fired steam generator without a significant loss of station efficiency. The project incorporates several unique aspects including low pH operation; a ceramic tile-lined, cocurrent/countercurrent, split module absorber; a wet stack supported on the roof of the FGD building; and closed loop, zero liquid discharge design producing commercial grade gypsum and calcium chloride brine. This paper provides an update of the current status of the project with emphasis on test results and operating experiences.

INTRODUCTION

In September, 1991, the United States Department of Energy awarded New York State Electric & Gas Corporation (NYSEG) a Clean Coal Technology Round IV grant for the Milliken Clean Coal Demonstration Project. Project team members include CONSOL Inc., Saarberg-Hölter-Umwelttechnik (S-H-U), Nalco/FuelTech, Stebbins Engineering and Manufacturing Co., DHR Technologies, and ABB Air Preheater. Project cofunders include DOE, NYSEG, CONSOL, Electric Power Research Institute (EPRI), New York State Electric Energy Research and Development Authority, and Empire State Electric Energy Research Corporation.

The overall project goals are:

- Space saving design;
- Demonstration of up to 98 percent SO_2 removal efficiency while burning high-sulfur coal;
- Production of marketable commercial-grade FGD gypsum and calcium chloride by-products to minimize waste disposal;

- *Zero FGD wastewater discharge;*
- 40 percent NO_x reductions through combustion modifications;
- Demonstration of additional NO_x reductions using selective non-catalytic reduction technology;
- Continued beneficial reuse of ash and;
- Maintenance of maximum station efficiency using a high efficiency air heater system and low-power scrubber system.

The host site for the demonstration is NYSEG's Milliken Station, located in the town of Lansing, New York. Milliken Station has two Combustion Engineering 150-MWe pulverized coal-fired units built in the 1950's.

SCHEDULE AND COST

Since this project was a compliance project for Phase I of the Clean Air Act Amendments of 1990, the schedule was set to meet the SO_2 and NO_x emission requirements of 1995. The design and construction period lasted from January 1992 to March 1995. During this period, Milliken Units 1 and 2 were retrofitted with the ABB Low NO_x Concentric Firing System III (LNCFS™ III) and the S-H-U FGD process. Unit 2 was also upgraded with a Heat Pipe Air Heater and the CAPCIS corrosion monitoring system. The operation and testing Phase of the demonstration began in July of 1995 and will be completed in July 1998.

The total cost of the project, including the three-year demonstration program, will be $158,607,807 with DOE contributing $45,000,000.

PROJECT DESCRIPTION

SO_2 Emission Control

The Milliken project SO_2 control system goals include: up to 98% SO_2 removal while firing a 3.2% sulfur coal, low energy consumption (approximately 1% of station net output), space-saving design, and 95% FGD reliability. The S-H-U process demonstrated in this project is a formic acid-enhanced wet limestone technology which produces high-quality, commercial-grade gypsum as a by-product.

The Milliken project features unique equipment design, construction methods, and materials of construction. The S-H-U scrubber handles flue gas from two boilers in a single, split, Stebbins tile, reinforced-concrete absorber module. This versatile method of construction can operate continuously in a pH range of 3 to 12. pH excursions above or below this range can be tolerated with little adverse effect. The liquid temperature limit is 200 °F and the gas temperature limit is much higher. The reinforced concrete/tile construction can tolerate chloride levels in excess of 100,000 ppm. The split module is constructed below the flues. This design feature saves space, reduces retrofit costs, and can be constructed in confined spaces using Stebbins construction methods. The system does not include a spare absorber module to save capital costs.

The S-H-U process has a significantly lower energy consumption than conventional wet limestone FGD systems because of its lower pressure drop and liquid-to-gas ratio. Because the S-H-U process is based on formic acid buffering of the recycle slurry, it is stable under all operating conditions. Since one of the Milliken project goals is zero waste water discharge, an important additional benefit of formic acid buffering is a lower FGD blowdown rate than a conventional scrubber. The smaller blowdown rate is due to the ability of the S-H-U process to maintain high SO_2 removal and high calcium utilization with greater than 50,000 ppm chloride in the recycle slurry.

PARTICULATE EMISSION CONTROL

The electrostatic precipitators for both Milliken Units 1 and 2 have been upgraded in order to limit the dust loading on the scrubbers. The upgrade was necessary to maintain the maximum marketability of the gypsum by-product. The new precipitators are designed with wide plate spacing and rigid discharge electrodes. New, computer-controlled transformer rectifier sets were also installed.

MINIMIZE WASTE PRODUCTION

Another Milliken project goal is to minimize solid and liquid waste production. To achieve this, the scrubber is designed for zero waste water discharge and to produce marketable by-products. NYSEG also plans to operate the burners in such a manner to minimize NO_x while producing marketable fly ash.

The scrubber and auxiliary systems are designed to produce marketable by-product gypsum and calcium chloride solution. A gypsum bleed stream from the scrubber is fed to hydrocyclones. The underflow from the primary hydrocyclone is fed to the centrifuges. The dewatered gypsum from the centrifuges is stored in a gypsum storage building prior to shipment by truck to end-users.

A bleed stream from the gypsum dewatering stream is pumped to the blowdown treatment area. The blowdown treatment system includes two principle subsystems: blowdown pretreatment and brine concentration. The blowdown pretreatment subsystem includes separate stages for gypsum desaturation and heavy metals precipitation and magnesium hydroxide precipitation. The brine concentration subsystem is separated into distillate and concentrated brine phases.

In the blowdown pretreatment subsystem, the pH of the bleed stream is increased by the addition of lime slurry to remove heavy metals from solution by precipitation as metal hydroxides. Gypsum seed crystals are recycled from the clarifier/thickener to accomplish gypsum desaturation. Additional removal of heavy metals can be obtained by their precipitation as sulfides through organosulfide dosing. After coagulation and flocculation, the waste water is separated into liquid and sludge phases in a clarifier/thickener. The magnesium ions in the supernatant are precipitated as magnesium hydroxide by pH adjustment with lime. The magnesium hydroxide sludge and heavy metals sludge are dewatered in a filter press for landfill disposal. The effluent from the clarifier/thickener is fed to the brine concentrator as raw make-up.

In the brine concentrator process, the pretreated blowdown is pH-adjusted by the addition of acid, preheated, deaerated, heated to near boiling point, and fed to a falling-film evaporator. Distillate from the evaporator is returned to the FGD system. The concentrated brine solution is fed to a storage tank.

NO_x EMISSION CONTROL

NO_x emission reductions are being demonstrated with two separate technologies, the LNCFS™ Level III system and the NO_xOUT® process [1]. The ABB LNCFS Level III low-NO_x system is being demonstrated on Milliken Units 1 and 2. The NO_xOUT demonstration, which was originally planned for Unit 1, is now being demonstrated at PENELEC's Seward Station Unit 5, a sister unit to both Milliken Units 1 and 2. The NO_xOUT demonstration is being combined with a SCR to demonstrate a SNCR/SCR Hybrid system funded by the EPA through the DOE. Demonstrating the SNCR process in a Hybrid system will allow a more complete assessment of the SNCR by permitting greater levels of ammonia slip while limiting the potential for air heater fouling. The Hybrid system combines the urea based SNCR system with a SCR system to enhance removal efficiencies and alleviate problems associated with ammonia slip from the SNCR process. The goal of the "Hybrid" system is to reduce NOx emissions by at least 55% over baseline conditions while improving chemical utilization.

The LNCFS Level III burner system utilizes staged combustion with close coupled and separated over fire air to reduce NO_x emissions. The design goals for the low-No_x burners are NO_x emissions of 0.39 lb/mmBtu while maintaining a high carbon burn-out rate, i.e., producing fly ash with low loss on ignition.

The NO_xOUT system provided by NALCO/Fuel Tech is a low capital cost, energy-efficient method of reducing NO_x emissions. The NO_xOUT process is a selective non-catalytic reduction (SNCR) technology. The system is a urea based post combustion NO_x reduction technology. The goal for the NO_xOUT demonstration is to reduce NO_x emissions by 30%.

The overall objective of the NO_x program is to minimize NO_x emissions utilizing different technologies in various combinations for maximum removal rates and accomplishing this in a cost-effective, energy-efficient manner while minimizing impacts on boiler equipment and marketable fly ash, gypsum, and calcium chloride solution. This approach provides greater flexibility for utilities to comply with current and proposed regulations.

MINIMAL IMPACT ON STATION EFFICIENCY

The impact of the scrubber system on Milliken Station thermal efficiency is minimized by the installation of a heat-pipe air heater and an improved boiler control system including boiler advisory control software. The heat-pipe installed on Unit 2 is zero-leakage and is capable of operating at reduced flue gas exit temperature. Energy

1 NO_xOUT is a registered trademark of Nalco Fuel Tech. LNCFS is a trademark of ABB Combustion Engineering, Inc.

efficiency benefits are derived through increased boiler efficiency and decreased power requirements for the forced and induced draft fans.

A CAPCIS corrosion control system is installed downstream of the heat-pipe air heater. The CAPCIS system is an on-line, real-time corrosion monitor. The CAPCIS system can be utilized to maintain minimum flue gas exit temperature without encountering excessive duct corrosion.

TEST PLAN

The test plan was developed to cover all of the new technologies utilized on the Milliken Clean Coal Technology Demonstration project. The new technologies demonstrated include the S-H-U FGD process, an ESP with wide plate spacing, combustion modifications for NOx reduction (LNCFS Level III), the NOxOUT selective noncatalytic reduction process and a high efficiency air heater. In addition, the project demonstrates that existing technologies can be used in conjunction with new processes to produce saleable by-products rather than waste. Supplemental monitoring has provided operation and performance data illustrating the success of these processes under a variety of operating scenarios. Monitoring data has confirmed the degree to which the demonstrated processes could meet design and regulatory requirements for new and existing generating stations.

The S-H-U FGD process was monitored to compare its performance to New Source Performance Standards (NSPS) and the 1990 Clean Air Act Amendment (CAAA) Title IV SO_2 emission limits. Monitoring was done to determine: (1) maximum percent reduction of SO_2, (2) short-term SO_2 emissions, and (3) annual SO_2 emissions.

The electrostatic precipitator was monitored to compare its performance to NSPS requirements as well as the FGD design limitations for particulate. Monitoring was done to determine: (1) maximum percentage reduction in particulate, (2) energy consumption, (3) short term particulate emissions and (3) annual particulate emissions.

The combustion modification and NOxOUT system for nitrogen oxide control was monitored to compare its performance to NSPS and CAA Title IV requirements . Monitoring was completed to determine: (1) maximum percent reduction of NOx, (2) short-term NOx emissions and (3) annual NOx emissions.

The heat pipe air heater was monitored to determine: (1) its maximum efficiency as a new installation, (2) efficiency in a fouled state, (3) recovery efficiency after cleaning and (4) frequency of maintenance cleanings to maintain operating efficiencies.

By-product production was monitored to collect data about the physical and chemical properties of: (1) gypsum, (2) fly ash, (3) bottom ash and (4) calcium chloride that result when the S-H-U, ESP, LNCFS-3 and NOxOUT processes are used. Utility and industrial boiler operators can use this data to evaluate the feasibility, economics, and environmental acceptability of the by product sale option demonstrated by this project.

Generally each test program is divided into four independent sub-tests as follows:

- Diagnostic
  These tests identify the component settings which provide optimized performance while maintaining operating and removal efficiencies with minimal impact to the station.
- Performance
  These tests verify that the optimized operation of the component is equivalent to the diagnostic test findings. The testing quantifies the diagnostic test performance.
- Long-Term
  This test monitors the operation and performance of the component over a 51 day period to demonstrate that the system is sustainable and can maintain performance over a long period of time.
- Validation
  This test demonstrates that the optimized component operation and performance is repeatable after a long term run.

FGD SYSTEM EVALUATION

The demonstration testing program for the FGD System is designed to characterize the performance of the S-H-U FGD process. The testing program is being conducted over a period of 36 months. The goals of the program are to demonstrate the effectiveness of the process at several operating conditions and to demonstrate the system's long term reliability and performance. Typical evaluations include SO_2 reduction efficiency, power consumption, process economics, load following capability, reagent utilization, by-product quality and additive effects.

Unit 1 was operated continuously at design conditions while parametric tests are performed on Unit 2 to define performance limits of the S-H-U FGD system. Because they are nearly identical modules, Unit 1 provided a baseline while the parametric tests were performed as well as serving as a long-term test. The parametric tests were set up to study the effects of formic acid concentration, L/G ratio, mass transfer, coal sulfur content and flue gas velocity on scrubber performance. Although load following capabilities were monitored, load was not a controlled variable. As much as possible, load changes during the parametric testing were handled by Unit 1 in order to keep Unit 2 at full load. The same coal was fed to both units simultaneously. The chloride content was not a controlled variable. At the design bleed rate chloride level was expected to stabilize at about 40,000 ppm Cl^- by weight when burning a 0.1 wt.% chlorine coal. Limestone utilization was held constant.

Test Parameters

A. Coal Sulfur Content

The plant design is based on a nominal coal sulfur content of 3.2 wt. %. The project is using Pittsburgh seam coal. The coal sulfur content is being varied over a range of 1.6 to 4.0 wt % using at least three different coals. Tests were performed using the lower sulfur coal first, followed by the design coal, and will conclude with a high sulfur coal. The high sulfur testing will be completed during a scheduled outage with one operating unit, because equipment for dewatering and reagent preparation is not designed to handle the output of both units simultaneously using high sulfur coal. Parametric tests will not be performed using high sulfur coal but the process will be operated at optimum conditions based on the results of the parametric tests using the design coal. The purpose of using high sulfur coal is to demonstrate the operability of the process using a 4% sulfur coal, not to determine the effect of operating parameters on performance.

B. Formic Acid Concentration

The process design is based on using 800 ppm formic acid in the scrubber slurry. Testing was conducted at 0, 400, 800 and 1600 ppm. Ideally, in this type of testing program, all parameters should be randomized; however, the large capacity (270,000 gal) in the scrubber sump makes it impractical to frequently increase and decrease the formic acid concentration. Therefore, the program is set up in blocks of tests in which the formic acid concentration is kept constant for long periods of time (4 to 25 days). Each block of tests was being conducted in order of increasing formic acid concentration, because it takes substantially more time to lower the concentration than to raise it.

C. Limestone Grind Size

The design limestone grind is 90% - 170 mesh when using formic acid and 90% - 325 mesh when using no formic acid. The design grind size limestone was used for all but a few test runs which were done to observe the effects of grind size on performance.

D. Spray Header Combination - L/G Ratio

There are four cocurrent spray headers and three countercurrent spray headers in each S-H-U module. The spray headers operate in an on-off mode, i.e., there is no flow control on the headers. The scrubber L/G ratio is varied by changing the number of spray headers in operation. The process design calls for operation of five spray headers to achieve 95% SO_2 removal and all seven headers to achieve >98% SO_2 removal. At least two of the headers should be operating at all times. In addition, at least one of the top two headers on the cocurrent side must be operating at all times in order to protect vessel internals from over temperature. Parametric testing includes operating various combinations of spray headers in the cocurrent and countercurrent sections to determine the combination that provides the best SO_2 removal performance and lowest scrubber energy consumption. For each combination, the uppermost headers were used. For each test coal, the pressure drop and SO_2 removal were measured for each spray header combination used. The gypsum crystal morphology and formic acid consumption rate were determined for selected spray header

The results of these tests were also used to determine the mass transfer coefficients individually for the cocurrent and countercurrent sections. The results from tests with all countercurrent sprays turned off were used to determine the mass transfer in the cocurrent section. The mass transfer in the countercurrent section was determined by comparing these results with results from tests in which countercurrent sprays are operating.

E. Gas Velocity in the Cocurrent Scrubber Section

The design gas velocity in the cocurrent scrubber section is 18 ft/sec. Tests at higher velocities were performed on the Unit 2 scrubber by shunting some of the gas flow from Unit 1 to the Unit 2 scrubber. The purpose was to provide data on high gas velocity scrubbers. These tests were performed using two formic acid concentrations (0 and 800 ppm) and two coals (lower sulfur coal and the design coal). The pressure drop and SO_2 removal were measured for several spray header combinations. The gypsum crystal morphology and formic acid consumption rate were determined for selected spray header combinations while using the design coal.

Test Description

a. Tests Using Design Gas Velocity - Lower Sulfur Coal

All of the possible spray header combinations were used for the tests using design gas velocity, design limestone grind size, and lower sulfur coal. Each test was repeated, giving 28 tests total at each formic acid concentration. In addition, two tests were done at each formic acid concentration using an alternative grind size. The effect of grind size was determined by comparing the results of these tests with the results of tests using the design grind size at the same header configuration and formic acid concentration.

B. Tests Using high Gas Velocity - Lower Sulfur Coal

These tests were performed using no formic acid and the design formic acid concentration (800 ppm). A minimum of five total headers were in service at all times. Five of the tests are being repeated, giving thirteen tests total. The tests were run in random order using the design limestone grind size. SO_2 removal was measured. Alternative grind sizes were not being tested. Gypsum crystal morphology was not characterized.

C. Tests Using Design Gas Velocity - Design Sulfur Coal

Fewer spray header combinations were tested using the design sulfur coal. Measuring and sampling during each test included SO_2 removal, pressure drop, gypsum crystal morphology (particle size distribution, sulfate/sulfite ratio, and SEM micrographs), gypsum samples for wallboard evaluation, calcium and sulfur balances and formate consumption rate. The larger (90% - 170 mesh) grind size is not being tested without formic acid.

The same tests that were run using the low sulfur coal at high gas velocity were run using the design coal. Alternative grind sizes were not tested. SO_2 removal was measured. Gypsum crystal morphology was not characterized.

The low sulfur and design sulfur tests have been completed as of January 1998. The results of the design sulfur test have not been fully analyzed to date. The following is a discussion of the known results:

1. The maximum SO_2 removal demonstrated has been 98% with all seven recycle pumps operating and using formic acid. The maximum removal without formic acid has been 95%. (See Figure 1)

2. The difference in SO_2 removal between the two grind sizes tested during the low sulfur testing (90% - 325 mesh and 90% - 170 mesh) was a minimum 2.6% absolute. (See Figure 2)

3. The SO_2 removal during the high velocity test was greater than the design velocity test up to a L/G ratio of 110. (See Figure 3)

4. The cocurrent pumps had no measurable effect on pressure drop, whereas countercurrent pumps significantly increased the scrubber pressure drop. The average effect of each countercurrent header was to increase pressure drop by 0.45 ins. WC in the design flow tests and 0.64 ins. WC in the high velocity tests. (See Figure 4)

ESP SYSTEM EVALUATION

This test program was established to determine the effectiveness of the Electrostatic Precipitators which were reduced in size and used wide plate spacing. Upgrades of the ESP on each unit consisted of replacement of the internals and retirement of part of the original ESP. A wide plate spacing design with a 16-inch plate spacing was provided by the ESP vendor, Belco Technologies, Inc. The modified unit is smaller and requires less power.

Performance tests were conducted on the original and modified ESPs utilizing the same coal during both tests. The modified ESP with less than one-half of the collection plate area had a better removal efficiency than the original unit. The voltage-current product data indicate that the power requirement is 25% less than that of the original ESP.

Milliken Station was extensively modified to accommodate a wet flue gas desulfurization system which in turn required modifications to the ESPs on Unit 1 and Unit 2. Design criteria for upgrading the precipitator were based, in part, on the requirements imposed by the flue gas desulfurization system designed by Saarberg-Hölter Umwelttechnik GmbH (S-H-U).

Originally, the Unit 2 particulate control system consisted of two ESPs in series, stacked one on top of the other. The ESP for each unit consisted of two independent sections with the gas flow separating upstream of the air heater and rejoining downstream of the final ESP. Each ESP section on Unit 2 consisted of two fields energized by a total of ten transformer-rectifier (TR) sets. During the modifications, the bottom ESP was completely removed while the top ESP was rebuilt. The internals of the top ESP were replaced using a wide plate spacing. An additional third field was added to the ESP. Six new computer controlled TR sets were installed replacing the original ones.

The plate spacing was increased from approximately nine inches to sixteen inches while the total number of fields decreased from four to three. The SCA at full load decreased from 392 to 175 ft^2 per 1,000 acfm of flue gas. Even with the reduced SCA, the new design was projected to have a higher removal efficiency. This is because the wider plate spacing permits higher applied voltages. The effectiveness increased 80%; that is, the new effectiveness is 1.8 times the original one (16 over 9). Similarly, the operating power was expected to decrease by 262 kW.

Testing of the original and modified ESPs was conducted to document the effect of the modifications. ESP inlet and outlet data were obtained for the following parameters:

- Total Particulate Matter (PM)
- Sulfur Dioxide (SO_2)
- Sulfuric Acid Mist (SO_3)
- Particle Size Distribution
- Flue Gas Composition (O_2, CO_2, N_2 and H_2O)
- Volumetric Flue Gas Flowrate
- Flue Gas Temperature
- Fly Ash Resistivity at the ESP Inlet

Coal and fly ash samples were collected and analyzed. TR set primary voltage, primary current and secondary current data were collected during the original baseline ESP performance evaluation. This information along with additional plant data was collected during the modified ESP performance evaluation.

Performance of the modified ESP exceeded that of the original ESPs at lower power. As the particle size decreases, the performance differences disappear. The performance was calculated from the total particulate concentrations into and out of the ESP. Penetrations for the <10 μm and <2.5 μm fractions were calculated using the daily particle size data. The size test provided the size distribution for the total particulate concentrations conducted on the same day.

The coal and fly ash properties did not change appreciably between the baseline test and the performance test on the modified ESP. Inlet fly ash particulate size consists also are similar. Coal sulfur levels, ash concentrations and higher heating values are similar on a dry basis. Fly ash carbon content was higher in the baseline test—4.04 wt % versus 2.40 wt %. Fly ash resistivities are also similar. Based on this information, the coal and fly ash properties were identical for both performance tests. Inlet solid concentrations were also similar for both test series. The inlet loading varied between 2.2 and 2.9 gr/dscf.

Results of the performance tests are shown in Figures 5 through 7. These figures show the penetration for the total, the <10 μm, and <2.5 μm size fractions. Figure 5 shows that the overall removal improves for the modified ESP, shown on the left portion of the figure. The average penetration before modification is 0.22 % versus 0.12 % after. For the <10 μm fraction and the <2.5 μm fraction, shown on Figures 6 and 7, respectively, the differences appear minimal. Penetration of these fractions is dominated by the finest particulate fractions. The very fine particulate is only a small portion of the total inlet sample and thus, small variations dominate the results. For example, the <2.5 μm fraction is less than 5% of the inlet material. For the particulate fraction >10 μm, the penetration is the same for both performance tests at 0.02 %.

The total V-I (voltage-current product) demands for the original and the modified ESP's is directly related to the power requirement. The modified ESP has 75% of the V-I demand of the original ESPs. The new TR sets show a higher primary voltage. The primary current is about the same; thus, since the modified area is about one-half that of the original ESP, the secondary voltage is about double that for the original ESPs with a 9-inch plate spacing. More than 50% of the V-I requirement is associated with the third field on each side of the modified ESP.

The modified ESP performs better than the original unit at a lower operating (power) cost. Overall penetration for the modified ESP is about half that of the original ESP. This improvement occurs with a 25% savings in V-I power requirements. The modified ESP has a smaller plant footprint with fewer internals and a smaller SCA. Total internal plate area is less than one-half that of the original ESPs, tending to lower the capital cost.

LNCFS Level III System Evaluation

This test program was established to determine the effectiveness of Low-NOx Concentric Firing System Level III (LNCFS-3) retrofit in reducing NOx emissions while maintaining high combustion efficiency and acceptable levels of carbon in the flyash. During the testing the boilers were firing a high volatile (37 - 38 % dry), medium sulfur (1.6-2.0%) Pittsburgh seam coal. Since both Units had comparable NOx emissions prior to the LNCFS conversion, Unit 2 was tested with the existing burners at the same time Unit 1 was tested with the LNCFS-3 burners.

This test program was established to meet two objectives: the first was to evaluate the difference in emissions levels between original burners and the new LNCFS-3 burner system; and to independently evaluate the LNCFS-3 burner system which included optimal performance, long term sustainable operation and repeatability.

Four test programs were conducted on each unit: diagnostic, long-term, validation and performance. The diagnostic tests were short term (2-4 hours), assessing the impact of operating variables on NO_x emissions and LOI. The variables included boiler load, excess air, coal air flow, burner tilt and mill pattern. In LNCFS-3, additional variables were tested , including mill classifier speed and overfire air parameters (flow, tilt and yaw). The long-term (60-70 days) tests assimilated the expected annual NO_x emissions. The validation tests re-assessed the impact of the most significant operating variables following long-term testing. These variables were boiler load, excess air and for LNCFS-3 only, mill classifier speed. The performance tests assessed the overall impact of the low NO_x burner retrofit on NO_x emissions, fly ash LOI, CO emissions and boiler efficiency.

The achievable annual NOx emissions, predicted using long-term measurements were .61 lb/mmbtu for the original burners and .39 lb/mmbtu for Unit 1 LNCFS-3. (Shown in Figure 8.)

Limited success was achieved in reproducing the diagnostic test results in the validation test programs because of the difficulty in reproducing the diagnostic test conditions. For example, control of overfire air during the LNCFS-3 diagnostic tests was limited, producing full boiler load LOI above 4%. The limitations were relaxed during the validation tests, producing 0.7% - 1.7% (absolute) lower LOI, with a minor effect on NOx emissions.

At full boiler load (145-150 MW) and 3.0%-3.5% economizer O2, the LNCFS - 3 burner lowered NOx emissions from a baseline of .64 lb/mmbtu to .39 lb/mmbtu (39% reduction). At 80-90 MW boiler load and 4.3%-5.0% economizer O2, the LNCFS-3 burner lowered NOx emissions from baseline of .58 lb/mmbtu to .41 lb/mmbtu (29% reduction). With the LNCFS-3 burner, fly ash LOI was maintained below 4%, and CO emissions did not increase.

The boiler efficiency was 89.3%-89.6% for baseline and 88.3%-88.5% for LNCFS-3. A lower LNCFS-3 boiler efficiency than baseline was attributed to higher post retrofit flue gas O2 and higher stack temperatures which accompanied the air heater retrofit. When LNCFS-3 and baseline were compared at similar flue gas temperatures and compositions, estimated LNCFS-3 boiler efficiency was .2% (absolute) higher than baseline.

HEAT PIPE EVALUATION

The ljungstrom air heaters on Milliken Unit 2 were replaced with two heat pipe air heaters fabricated by ABB Air Preheater. The air heater installation was part of the CCT-IV demonstration program to evaluate the feasibility of the heat pipe air heater design to improve boiler heat rate and reduce air leakage into the system.

Three detailed performance tests were conducted on the Milliken heat pipe air heaters. The first test was to establish the performance of the heat pipe in its new unfouled condition. However, delays in testing due to problems with the heat transfer solution, resulted in testing in a clean condition after it was fouled. The second test was performed in a fouled condition and the last test was in a clean condition after fouling. The original intent with the testing was to evaluate the heat pipe performance after start up while the equipment was in its new condition. This would establish the baseline for the maximum expected performance. The fouled test was to bench mark the deterioration of the heat pipe over time and establish an operating curve. The third test was to evaluate the recovery rate of the heat pipe after cleaning.

Each test was completed over a three day period. Each heat pipe was tested separately. The testing was performed in general accordance with the procedures outlined in the ASME Power Test Code for Air Heaters, ASME PTC 4.3. The main objectives of the tests were to:

- Measure thermal performance at full load (145-150 MW) and optionally, low load (90-100 MW) conditions.

- Measure primary air side, secondary air side and flue gas side pressure drops at full load.

- Determine air inleakage on the system.

Since the original testing of the heat pipe required the system to be cleaned prior to testing, the original test did not reflect the equipment at its maximum efficiency. Lessons learned during the initial cleaning resulted in changes in the cleaning procedure and the start up procedure for the heat pipe. Therefore, the second test better represented the heat pipe in its cleanest condition. The second test was conducted in November 1996, three weeks after the heat pipe was manually cleaned and inspected. The test results indicated the following:

1. Air infiltration is low for both heat pipes. The unaccounted for air inleakage rates at full load ranged between 2. and 2.4 wt. percent. The primary source of the leakage is believed to be infiltration at sootblower wall penetrations.

2. The flue gas side pressure loss for both heat pipes was less than the design maximum of 3.65 in. WC.

3. The primary side pressure drops for both heat pipes were less than the design maximum of 3.6 in. WC.

4. The secondary air side pressure drops for both heat pipes were less than the

design maximum of

5. The exit gas t
"A" heater an
of uncertainty

OPERATIONAL EX

To demonstrate a sp
directly above the m
on the modules. As
FGD.

related to the mixing characteristics in the module. Therefore, no major modifications to the agitators are being considered at this time.

To date, the goal of producing a marketable calcium chloride solution from the FGD blowdown stream has not been achieved. The brine can be concentrated to 33%. However, the amount of dissolved solids caused by the level of impurities in the FGD blowdown is higher than that allowed by ASTM D-98 Type L standards. The system has also experienced severe operational problems. Scaling and pluggage in the brine concentrator vessel have caused excessive system down-time and repair requirements. Attempts to change the chemistry in the system to improve the system operability have been inconclusive and have not improved the quality of the brine product. The goal of demonstrating zero waste water discharge from the FGD has been demonstrated, but only during short periods when the brine concentrator has been operational.

The goal of demonstrating 40% reductions in NO_x emissions while maintaining fly ash marketability has been achieved. The limit of loss on ignition for marketable fly ash from the station is 4%. The combination of the LNCFS Level III burners and the installation of new pulverizers with dynamic classifiers has made this target achievable. The 4% limit is only exceeded when reductions in NO_x greater than design are required to meet system operating requirements. The station has experienced problems burning coals with high levels of volatiles. The flames can burn back into the nozzle tips and cause damage to the burners.

The goal of demonstrating up to 30% NO_x reductions by using the NO_xOUT technology has been demonstrated at PENELEC's Seward Station. Data from testing done at Seward indicate the NO_x level was reduced from a baseline of 0.78 lb/mmBtu to 0.45 lb/mmBtu, or a 42 % reduction. The main problem experienced with the system is the control of the ammonia slip. One of the by-products of the urea injected into the boiler is ammonia. The ammonia reacts with sulfur tri-oxide in the flue gas to form ammonium bi-sulfate in the air heaters. If the ammonia slip is not consistently maintained below 2 ppm, significant pluggage of the air heater can result in a short period of time.

STATION EFFICIENCY

The project goal of maintaining maximum station efficiency has been achieved with marginal success. The heat pipe air heater has demonstrated a zero leakage design requiring less fan power. However, the heat pipe has not been able to achieve as low of an exit gas temperature as required. The air heater also tends to foul, requiring a unit outage every six months to clean and restore efficiency and reduce pressure drop. In an attempt to extend the run time between cleanings, a sonic sootblower was installed. However, the system was not designed for this type of device and there was limited success. The sonic vibrations transmitted by the sootblower also caused structural damage to the ductwork. The tubes in the heat pipe have also experienced leakage of their working fluids.

Since the heat pipe has not been able to reduce exit gas temperatures to the design level, the CAPCIS corrosion monitoring system has not been used to its fullest capability. Two CAPCIS probes are installed in the outlet duct from the heat pipe air heater and two probes are installed at the inlet to the S-H-U scrubber. Inspections of the probe ends have indicated no measurable corrosion, which is in line with the output from the corrosion monitor.

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3. E.S. Baron, et. al., Miliken Station Demonstration Project FGD Retrofit Update - 1995, Fourth Annual Clean Coal Technology Conference, Denver, Co, September, 1995

4. J. Urbas and J. Boyle, Results of SNCR/SCR Hybrid No_x Reduction on a Group 1 Boiler in the Ozone Transport Region, Power-Gen '97 International, Dallas, Tx, December, 1997

5. D.H. Kessler, J.F. O'Leary, J.R. Urbas and W.E. Cummings, An SNCR Experience With Low Ammonia Slip and Rapid Air Heater Fouling, EPRI Workshop For NOx Controls On Utility Boilers, Cincinnati, OH, August, 1996

SO_2 REMOVAL VS TOTAL NUMBER OF HEADERS

IN TESTS USING AT LEAST 2 COUNTERCURRENT HEADERS

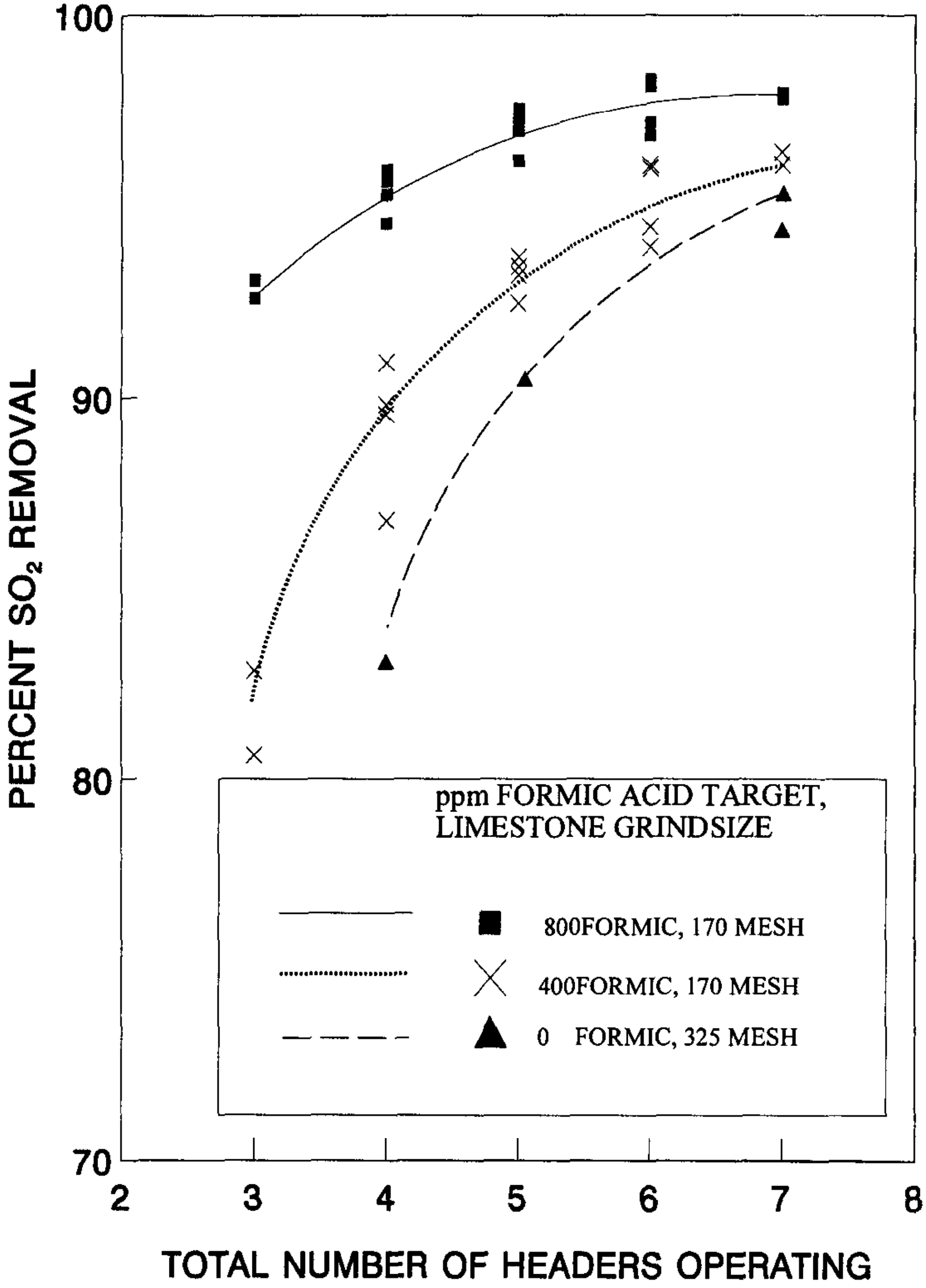
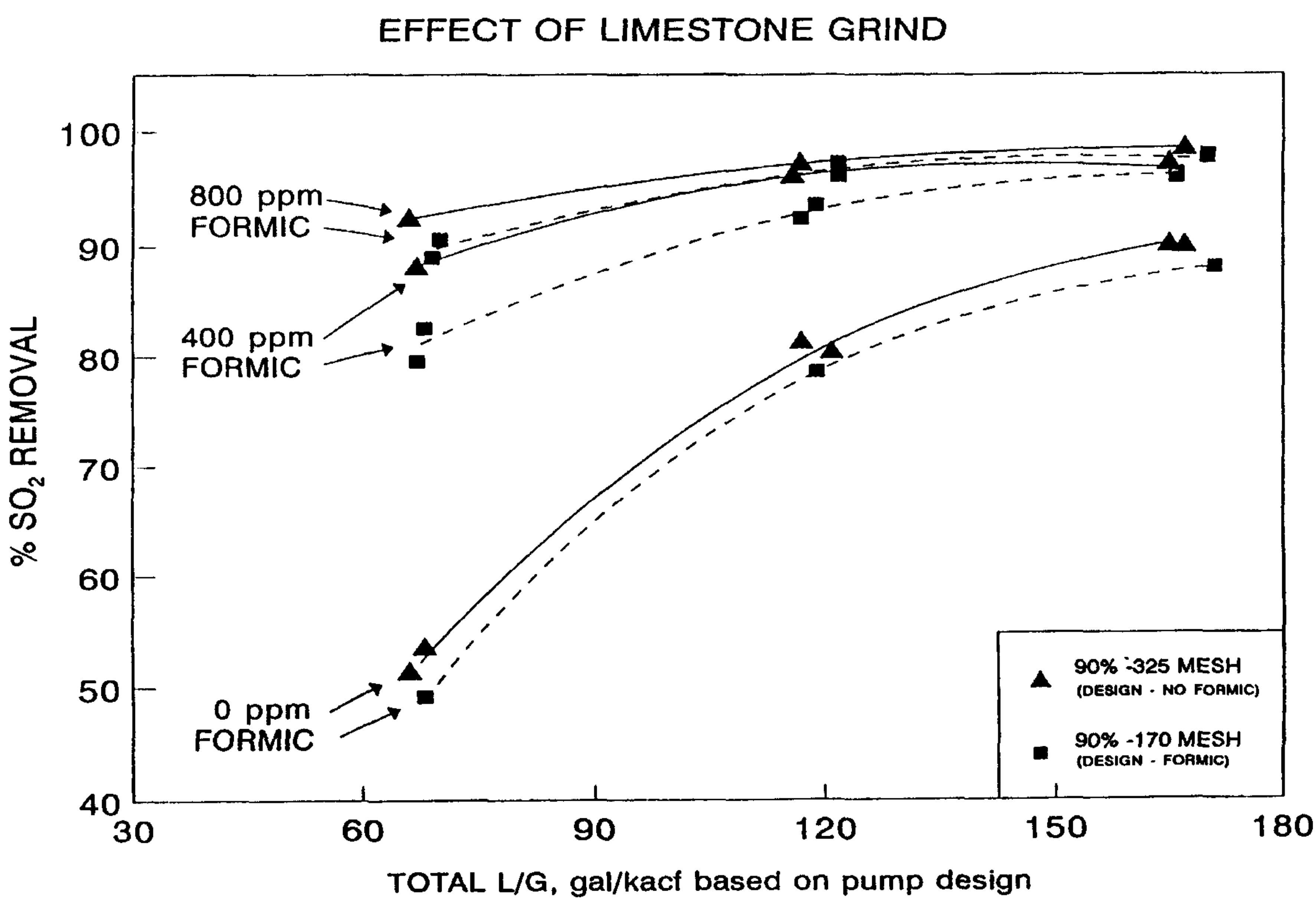
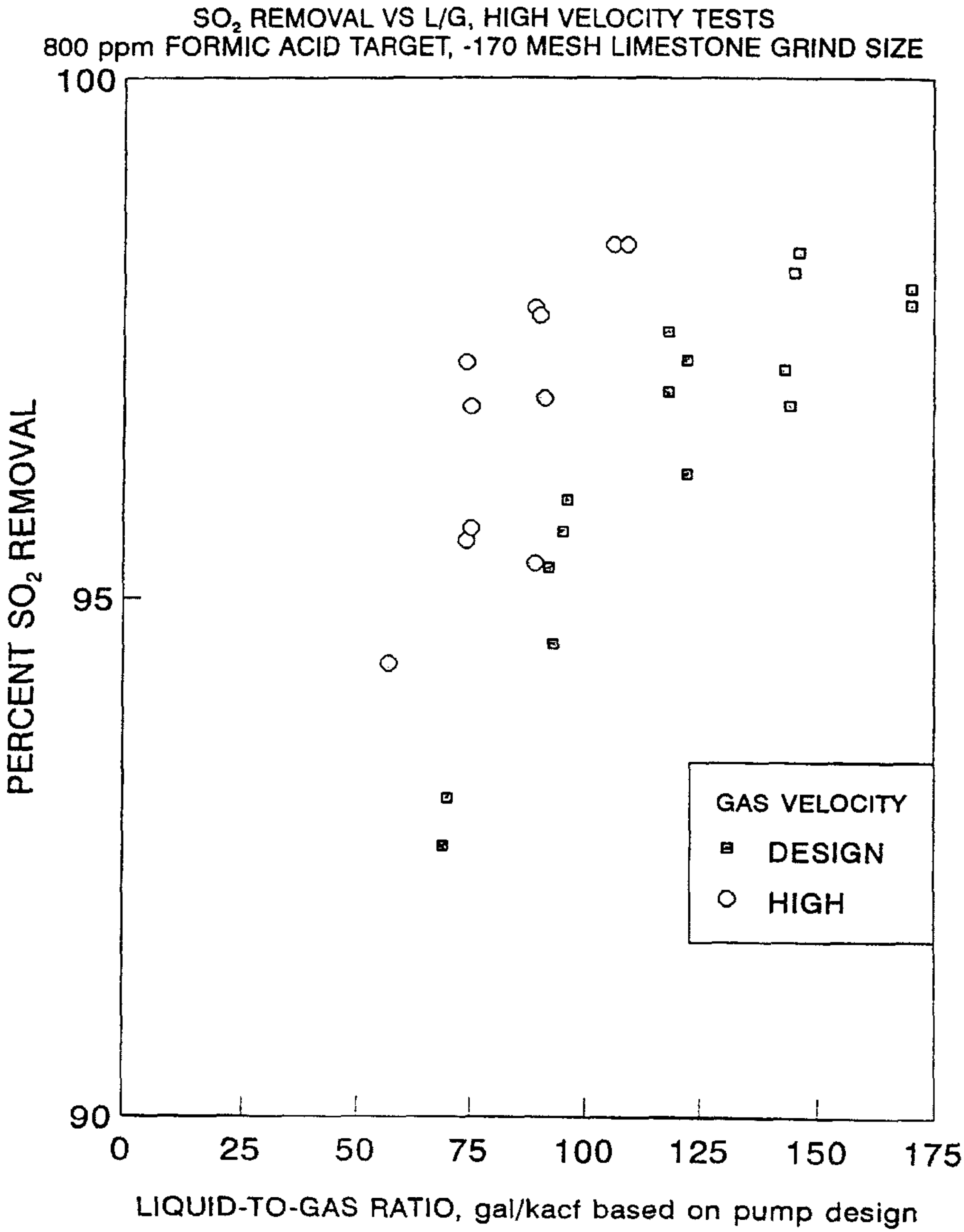


Figure 1



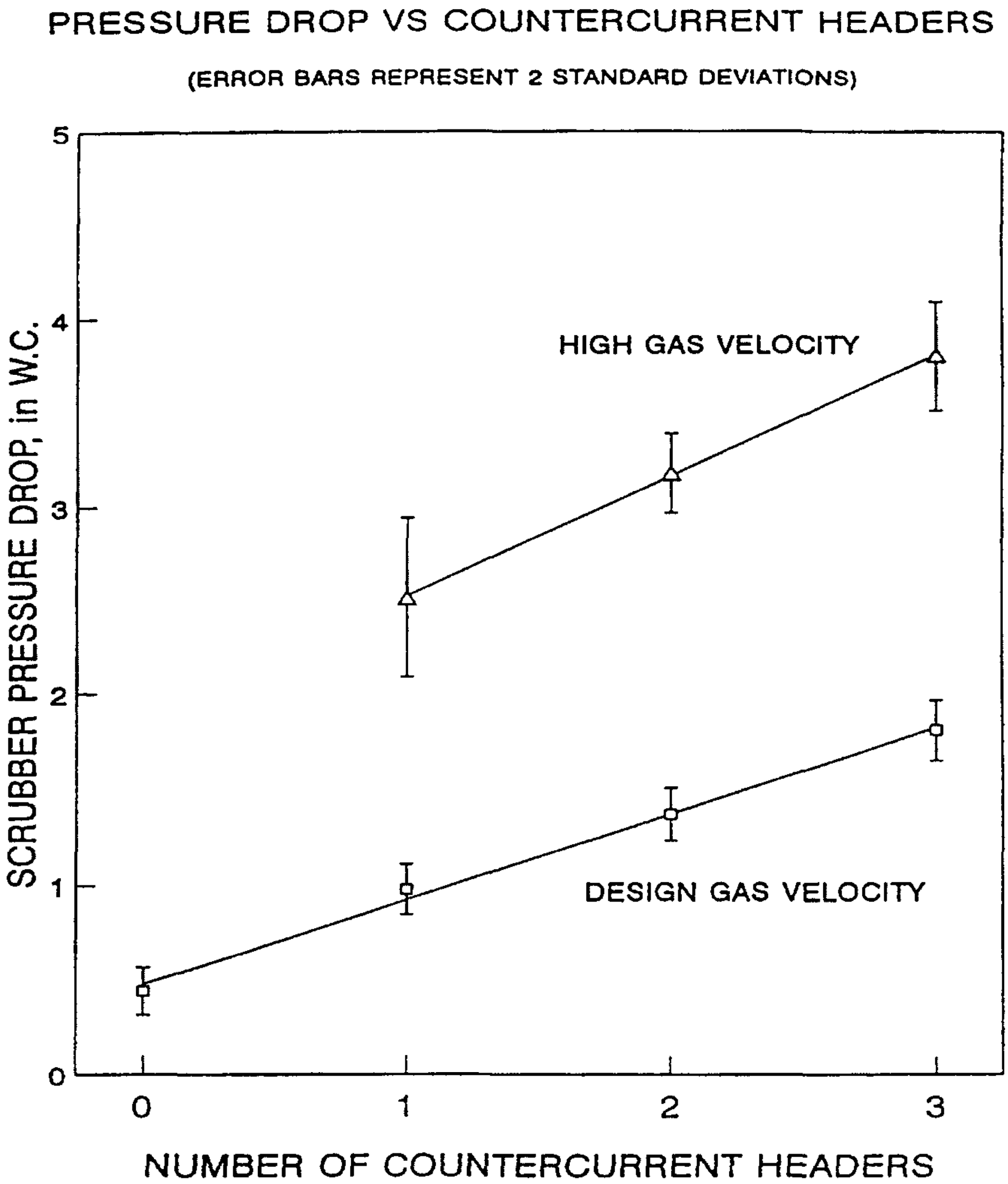
EFFECT OF LIMESTONE GRIND
% SO_2 REMOVAL
100
90
80
70
60
50
40
30
60
90
120
150
180
TOTAL L/G, gal/kacf based on pump design
800 ppm
FORMIC
400 ppm
FORMIC
0 ppm
FORMIC
90% -325 MESH
(DESIGN - NO FORMIC)
90% -170 MESH
(DESIGN - FORMIC)

Figure 2



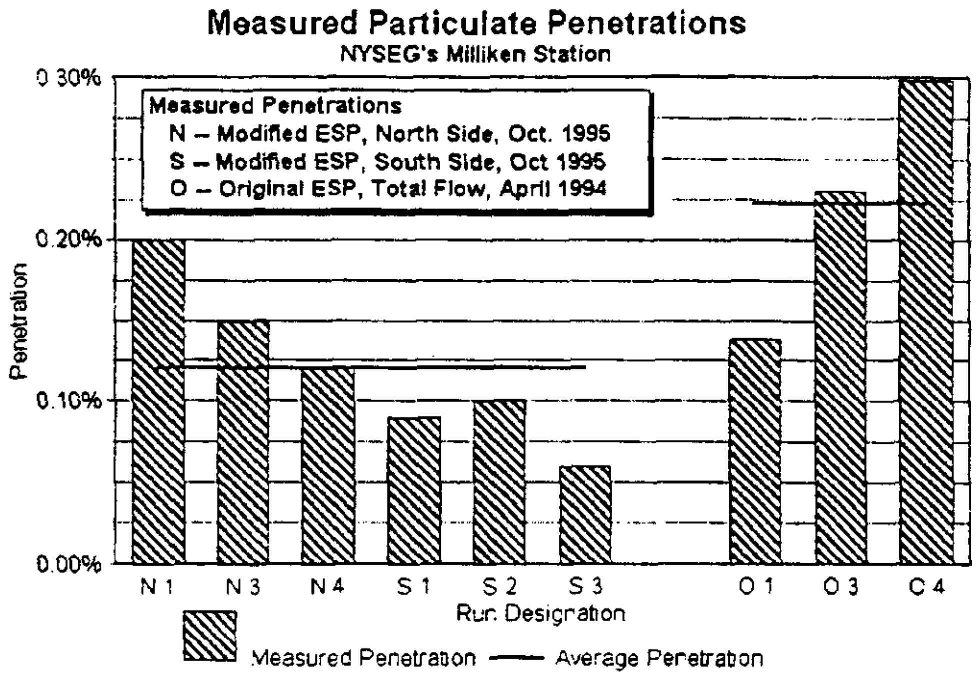
SO_2 Removal vs Total L/G Showing the Effect of Gas Velocity.

Figure 3



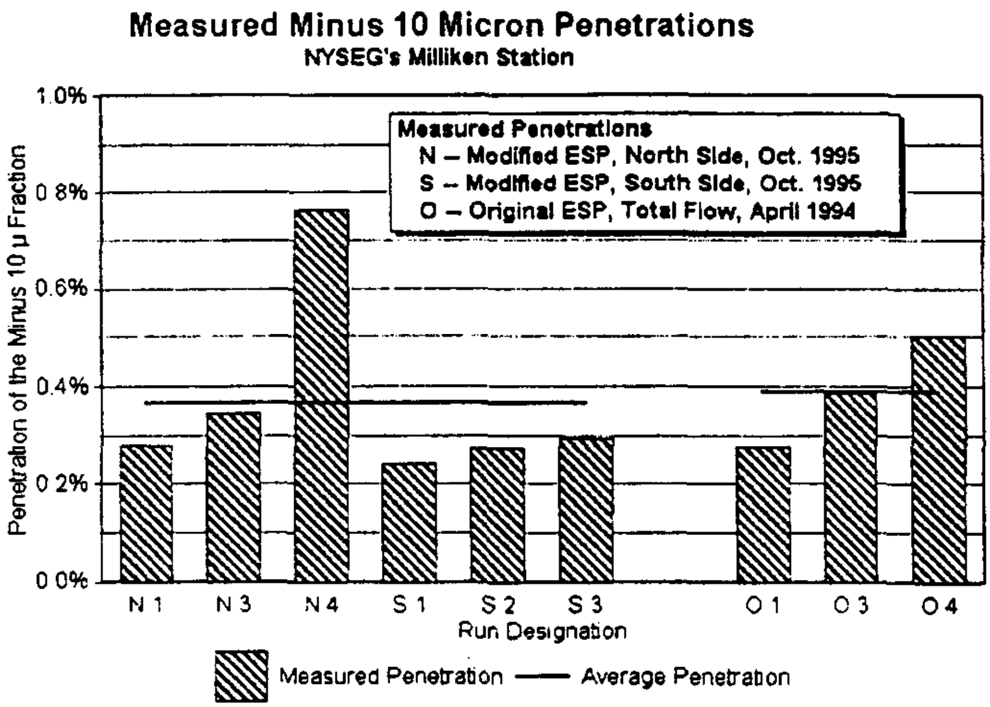
Scrubber Pressure Drop vs Number of Countercurrent Headers Operating.

Figure 4



Measured Particulate Penetrations
NYSEG's Milliken Station
0.30%
0.20%
0.10%
0.00%
Penetration
Measured Penetrations
N – Modified ESP, North Side, Oct. 1995
S – Modified ESP, South Side, Oct 1995
O – Original ESP, Total Flow, April 1994
N 1
N 3
N 4
S 1
S 2
S 3
O 1
O 3
C 4
Run Designation
Measured Penetration
Average Penetration

Figure 5



Measured Minus 10 Micron Penetrations
NYSEG's Milliken Station
Measured Penetrations
N – Modified ESP, North Side, Oct. 1995
S – Modified ESP, South Side, Oct. 1995
O – Original ESP, Total Flow, April 1994
Penetration of the Minus 10 μ Fraction
1.0%
0.8%
0.6%
0.4%
0.2%
0.0%
N 1
N 3
N 4
S 1
S 2
S 3
O 1
O 3
O 4
Run Designation
Measured Penetration
Average Penetration

Figure 6

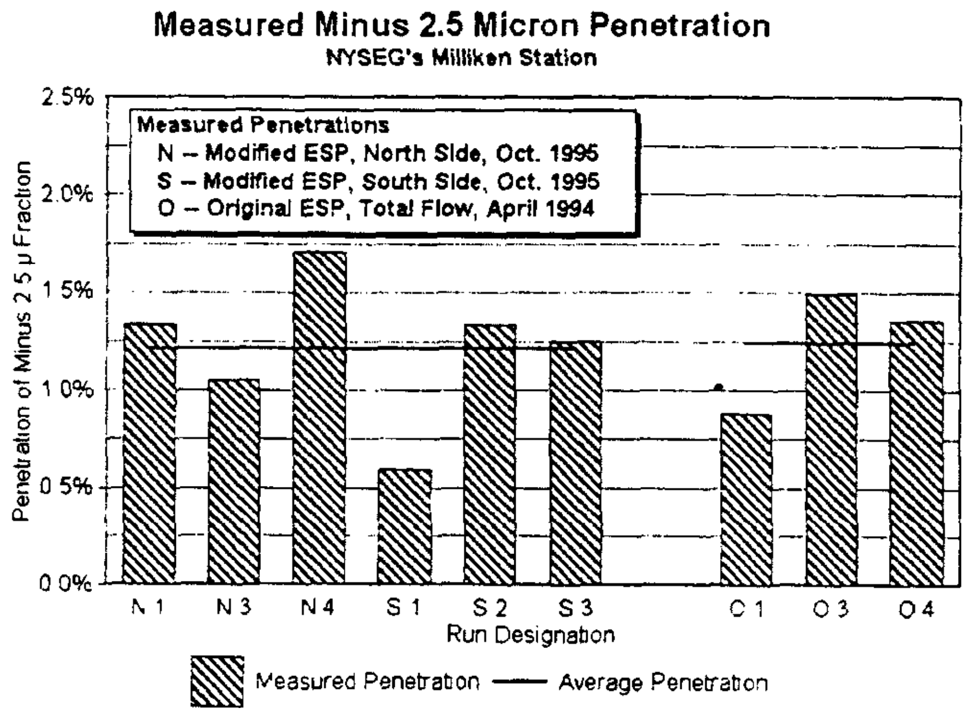

Measured Minus 2.5 Micron Penetration
NYSEG's Milliken Station
Measured Penetrations
N -- Modified ESP, North Side, Oct. 1995
S -- Modified ESP, South Side, Oct. 1995
O -- Original ESP, Total Flow, April 1994
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
Penetration of Minus 2.5 µ Fraction
N 1
N 3
N 4
S 1
S 2
S 3
O 1
O 3
O 4
Run Designation
Measured Penetration
Average Penetration

Figure 7

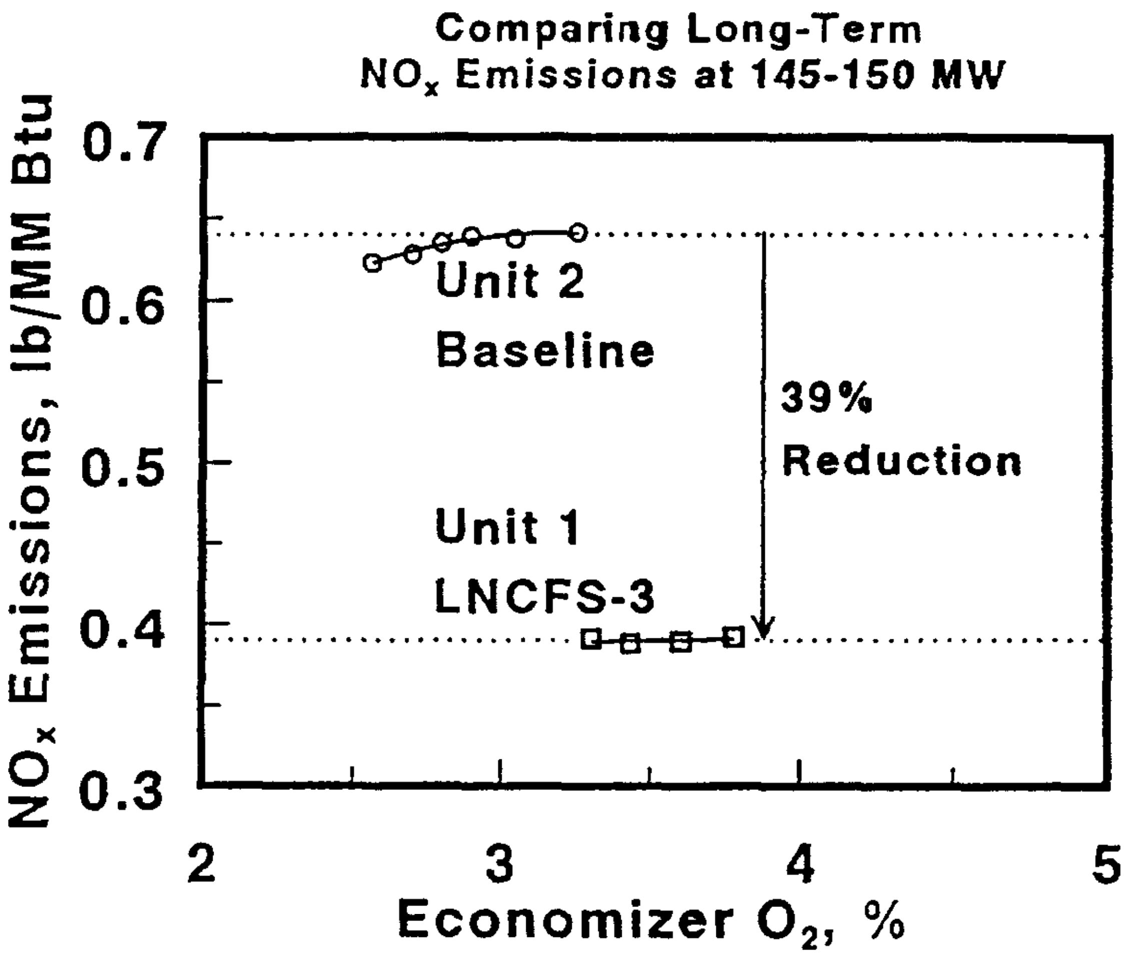

Comparing Long-Term
NOx Emissions at 145-150 MW
NOx Emissions, lb/MM Btu
0.7
0.6
0.5
0.4
0.3
Unit 2
Baseline
39%
Reduction
Unit 1
LNCFS-3
2
3
4
5
Economizer O2, %

Figure 8

Unit 2 Heat Pipe

Performance Summary -- Fully Corrected Flue Gas Outlet Temperatures

Unit	**A**		**B**	
Date	11/7/96	11/8/96	11/7/96	11/8/96
Time	12:40-16:22	10:15-12:28	16:25-19:38	12:15-14:50
Boiler Load, MW net	146.9	147.8	146.8	147.8
Primary Flue Gas Section				
Primary Flue Gas Flow, lb/hr	92,980	97,000	80,490	91,570
Measured Outlet Temp, °F	324	288	325	283
Temperature Corrections For Differences From:				
Design Entering Air Temp, °F	302	271	303	265
Design Entering Flue Gas Temp, °F	332	295	332	289
Design X-Ratio, °F	299	315	316	308
Design Flue Gas Flow Rate, °F	324	287	328	283
Air Leak Correction, °F	44	34	24	34
Fully Corrected Outlet Temp, °F	**329**	**337**	**327**	**329**
Secondary Flue Gas Section				
Secondary Flue Gas Flow, lb/hr	655,100	658,600	658,200	686,500
Outlet Temp (Ht Bal), °F	283	276	290	283
Temperature Corrections for Differences From:				
Design Entering Air Temp, °F	274	273	281	281
Design Entering Flue Gas Temp, °F	290	284	296	290
Design X-Ratio, °F	268	264	265	257
Design Flue Gas Flow Rate, °F	283	276	290	281
Fully Corrected Outlet Temp, °F	**265**	**267**	**262**	**260**
Fully Corrected Temperatures				
Combined Flue Gas Outlet, °F	**273**	**276**	**269**	**268**
Design Flue Gas Outlet Temp, °F	253	253	253	253
Outlet Temp Approach To Design, °F	**20**	**23**	**16**	**15**

Figure 9

ADVANCED COAL CONVERSION PROCESS DEMONSTRATION

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Power plants switching to low-rank coals frequently experience derating and increased transportation costs when switching to these high-moisture-content fuels. This has driven significant interest in developing processes to upgrade low-rank coals to take advantage of their low sulfur content while avoiding problems associated with their handling, transportation, and use as boiler fuels. DOE selected the Advanced Coal Conversion Process (ACCP) for demonstration under Round I of the Clean Coal Technology Demonstration Program. Development of the ACCP has been beneficial to the industrial sector and resulted in new applications for low-rank coals and has advanced the knowledge about upgrading low-rank coals for utility use. The status of this ACCP demonstration project and the potential for commercialization of this technology are discussed.

I. INTRODUCTION

The Advanced Coal Conversion Process (ACCP) being demonstrated in Colstrip, Montana, consists of thermal processing coupled with physical cleaning to upgrade high-moisture, low-rank coals, producing a fuel with improved heating value and low sulfur content.

The process and product, patented as SynCoal®, has been developed by the Rosebud SynCoal Partnership (RSCP) as part of Round I of the U.S. Department of Energy's Clean Coal Technology Program. RSCP is a general partnership formed in December 1990 for the purpose of conducting the demonstration and commercializing the ACCP technology. Western SynCoal Company (WSC), a subsidiary of Montana Power Company's Energy Supply Division, is the managing general partner.

WSC owns the technology and has exclusively licensed it to the partnership. The partnership manages the demonstration project and all activities related to commercialization. DOE is contributing about $43 million (41%) to the $105 million demonstration project, with the remainder provided by RSCP.

The Cooperative Agreement with DOE for the ACCP demonstration facility was signed in September 1990 with an original 66-month duration. The project has been extended twice, with a current project completion date of December 1998. RSCP has proposed a restructuring of the Cooperative Agreement which, if finalized would significantly expand the project scope while resulting in a no-cost time extension into 2002.

The plant is located adjacent to the unit train loadout facility within Western Energy Company's Rosebud Mine near Colstrip, Montana (see location map). The production unit, having a capacity of 1,000 tons per day of upgraded coal, is one-tenth the size of a commercial facility and benefits from the existing mine and community infrastructure.

Technology Overview

The SynCoal® process enhances low-rank subbituminous and lignite coals by a combination of thermal processing and physical cleaning. The process consists of three major steps: thermal treatment in an inert atmosphere, inert gas cooling of the hot coal, and pneumatic cleaning (see the simplified process flow diagram). The results are a reduction in moisture content from 25-40% in the feedstock to as low as 1% in the product, concurrently increasing heating value from 5,500 – 9,000 Btu/lb to as high as 12,000 Btu/lb. At the same time, sulfur content is reduced from a range of 0.5 – 1.5% to as low as 0.3%. Each ton of raw Rosebud subbituminous coal produces about 2/3 ton of SynCoal®.

Raw coal from the Rosebud mine unit train stockpile is screened and fed to a vibratory fluidized-bed reactor, where surface water is removed by heating with hot combustion gas. Coal exits this reactor at a temperature slightly higher than that required to evaporate water and is further heated to nearly 600°F in a second vibratory reactor. This temperature is sufficient to remove chemically bound water, carboxyl groups, and volatile sulfur compounds. In addition, a small amount of tar is released, partially sealing the dried product. Particle shrinkage causes fracturing, destroys moisture reaction sites, and liberates the ash-forming mineral matter.

The coal then is cooled to less than 150°F by contact with an inert gas (carbon dioxide and nitrogen at less than 100°F) in a vibrating fluidized-bed cooler. Finally, the cooled coal is fed to deep bed stratifiers where air pressure and vibration separate mineral matter including much of the pyrite, from the coal, thereby reducing the sulfur content of the product. The low-specific-gravity fractions are sent to a product conveyor while heavier fractions go to fluidized bed separators for additional ash removal.

The fines handling system consolidates the coal fines that are produced in the conversion, cleaning and material handling systems. The fines are gathered by screw conveyors and transported by drag conveyors to a bulk cooling system. The cooled fines are blended with the coarse product or stored in a 250-ton capacity bin until loaded into pneumatic trucks for off-site sales. When sales lag production, the fines are slurried with water in a specially designed tank and returned to the mine pit.

II. PROJECT STATUS

The ACCP technology is at a critical juncture in its development as it nears the end of the current Cooperative Agreement.

Through December 1997, 1.8 million tons of raw coal have been processed and over 1.1 million tons of SynCoal® has been produced. Total shipments of SynCoal® products have exceeded 1 million tons. The plant has consistently operated at over 100% of its design capacity and at its target 75% availability. The demonstration facility is currently scheduled to operate through June 1998 under the Cooperative Agreement.

While the project has already been successful and has made substantial progress in reducing its cost structure so that it has a chance to continue operations after the Department of Energy support is exhausted, it still struggles from the lack of market commitment. The recent loss of regular deliveries to Colstrip Units 1 & 2 has forced the ACCP facility into a cycling operation, running about two weeks each month. This event has put additional pressure upon the business plans to continue operating after the Cooperative Agreement expires. RSCP has developed a "going forward plan" which would re-establish a base market for any production in excess of the specific industrial market commitments. The key element of this plan would be the installation of a new SynCoal® delivery system, which would provide selectively controlled pneumatic delivery of the SynCoal® product to individual pulverizers in Colstrip Unit 2.

This system is critical to the "going forward plan" by providing access to a flexible, long-term committed market upon which a business plan can be based. A decision on this project will be made shortly which will determine the long-range potential of the SynCoal® technology. Additionally, this system would allow controlled testing with a live side-by-side comparison between the twin 320 megawatt tangentially fired PC units, Colstrip Units 1 & 2. This side-by-side testing should provide valuable comparative data on emissions performance and slag reduction.

III. OPERATIONAL EXPERIENCE

Initial operations began in April 1992, with the first 24-hour run occurring in May 1992 and the first significant shipments in June 1992. Several material handling problems were encountered during initial operations that required extensive modifications and hampered the efforts to address the product issues of dustiness and spontaneous heating. Parallel efforts to correct the material handling shortfalls and investigate treatments to mitigate the product issues were pursued until August 1993, when the demonstration facility reached full production capability. Efforts have continued since to establish test customers and address the product handling issues for safe and reliable transportation and handling.

Corette Testing

A SynCoal® testburn was conducted at the 160 MW J.E. Corette plant in Billings, Montana. A total of 321,528 tons of SynCoal® was burned between mid-year 1992 and April 1996. The testing involved both handling and combustion of dust and stability enhanced (DSE treated) SynCoal® in a variety of blends. These blends ranged from approximately 15% to 85% SynCoal® with raw coal. Overall, the results indicate that a 50% SynCoal®/raw coal blend provides improved performance, with SO_2 emissions reduced by 21% at normal operating loads, and no noticeable impact on NO_x emissions.

In addition, the use of SynCoal® permitted deslagging the boiler at full load, thereby eliminating costly ash shedding operations. This also provided reduced gas flow resistance in the boiler and convection passage, thereby reducing fan horsepower and improving heat transfer in the boiler area, resulting in an increase in net power generation of about 3 MW.

Alternative Feedstock Testing

Three different feedstocks were trucked to and tested at the facility in 1993 and early 1994. In May 1993, 190 tons of Center, North Dakota lignite were processed at the ACCP demonstration facility, producing a 10,740 Btu/lb product, with 47% reduction in sulfur and 7% reduction in ash. The Center lignite before beneficiation had 36% moisture, about 6,800 Btu/lb, and about 3.0 lb of SO_2/million Btu. In September 1993, a second test was performed processing 532 tons of lignite, producing a 10,567 Btu/lb product with 48% sulfur reduction and 27% ash reduction.

Approximately 190 tons of these upgraded products were burned in the Milton R. Young Power Station Unit #1, located near Center. This initial test showed dramatic improvement in cyclone combustion, improved slag tapping, and a 13% reduction in boiler air flow, reducing the auxiliary power loads on the forced draft and induced draft fans. In addition, the boiler efficiency increased from 82% to over 86% and the total gross heat rate improved by 123 Btu/kWh.

Similar test programs were also conducted on 290 tons of Knife River lignite from North Dakota and 681 tons of Amax subbituminous coal from Wyoming, producing 10,670 Btu/lb and 11,700 Btu/lb products, respectively.

Industrial Testing

In 1994, several test burn programs were conducted in industrial applications and three regular customers were established. Several industrial cement and lime plants have been customers of SynCoal® for an extended period of time. Over 190,000 tons have been delivered to Ash Grove Cement, Wyoming Lime Producers and Continental Lime since 1993. They have found that SynCoal® improves both capacity and product quality in their direct-fired kiln applications, because the steady flame produced by SynCoal® appears to allow tighter process control and improved process optimization.

A bentonite producer, Bentonite Corporation, has been using SynCoal® as an additive in greensand molding product for use in the foundry industry, having purchased about 37,500 tons. They have found SynCoal® to be a very consistent product, allowing their greensand binder customers to reduce the quantity of additives used and improving the quality of the metal castings produced.

Operating Lessons

Mechanical Reliability

Initial operations of the demonstration plant discovered numerous weak links and bottlenecks. The rotary airlocks between process reactors were under-powered and jammed tripping the entire plant. The fines gathering and conveying system was severely undersized and wore out rapidly. As operations continued, problems with fan bearings, conveyors and particularly the vibrating reactor vessels were uncovered. Generally all of these problems have been solved or mitigated by improved design and repair or replacement. These lessons can be carried forward to the next-generation plant design.

Product Issues

The project team has worked continually to improve the process and product since the initial startup identified the dustiness and spontaneous combustion issues. Additionally, as with any first-of-a-kind plant, significant efforts have been directed toward improving process efficiencies and reducing overall costs. A CO_2 inerting system was added to prevent self heating in the storage areas and enhance the product stability in transit to customers. After verifying the effectiveness of this system, an additional inert gas process was added to reduce the gas expenses and further test the impact on product stability.

A wide variety of additives and application techniques were tested in an effort to reduce dustiness and spontaneous combustion. A commercial anionic polymer applied in a dilute concentration with water was found to provide effective dust control and is environmentally acceptable. A companion product was identified that can be used as a rail car topping agent to reduce wind losses. The application of the dilute water-based suppressant, which is known as dust and stability enhancement (DSE), also provided a temporary heat sink, helping control spontaneous combustion for short duration shipments and stockpile storage. This work led to extensive investigation of stockpile management and blending techniques.

After adapting these lessons, safe and effective techniques for blending SynCoal® with raw coal, petroleum coke, and SynCoal® fines and handling the resultant products have evolved. This work further led to the development of stabilization process concepts (patents pending) which were successfully piloted at a 1,000 lb/hr scale. A plant modification was designed, but has not been installed due to the high retrofit costs. The next-generation plant is expected to incorporate the stabilization process technology.

Environmental Performance

It was originally assumed that SO_2 emissions would have to be controlled by injecting chemical sorbents into the ductwork. However, a mass spectrometer installed to monitor emissions and performance testing, discovered that the process configuration inherently limits the gaseous sulfur production, eliminating the need for chemical sorbent injection. The sorbent injection system remains in place should a higher sulfur coal be processed.

Fugitive dust from material handling and coal cleaning operations throughout the plant is controlled by negative-pressure dust collection hoods located at all transfer points and other dust emission sources. High-efficiency baghouses are connected to the dust collection hoods. These baghouses have been effective, as demonstrated by stack tests on the east and west baghouse outlet ducts and the first-stage drying gas baghouse stack in 1993. Emission rates are well within the limits specified in the air quality permit, at 0.0013 grains/dry standard cubic feet (gr/dscf) for the baghouse outlet ducts and 0.0027 gr/dscf for the drying gas baghouse stack. Another stack survey conducted in May 1994 verified that emissions of particulates, SO_2, oxides of nitrogen (NO_x), carbon monoxide (CO), total hydrocarbons, and hydrogen sulfide (H_2S) from the process stack are within permitted levels.

Through December 1997, the demonstration operations have been cited for only five minor violations as a result of MSHA's regular inspections. It was noted at the celebration of 1 million tons of production in June 1997 that the operating work force had completed over 300,000 manhours without a lost-time accident.

IV. TECHNOLOGY DEVELOPMENT NEEDS

Additional development is required to improve two major product characteristics: spontaneous combustion and dusting. In addition, further market development and customer education are needed to position SynCoal in the proper market niches and overcome natural resistance to a new product.

The upgraded coal produced to date has exhibited spontaneous heating and combustion. When a coal pile (more than 1 to 2 tons) is exposed to any significant airflow for periods ranging from 18 to 72 hours, the coal reaches temperatures at which spontaneous combustion or autoignition occurs. Spontaneous heating of run-of-mine, low-rank coals has been a common problem but usually occurs after open-air exposure periods of days or weeks, not hours. However, dried, low-rank coals have universally displayed spontaneous heating tendencies to a greater degree than raw low-rank coals.

Because of numerous steps where the coal is fluidized in process gas or air, which removes the dust-size particles, the product is basically dust free when it exits the processing facility. However, typical of all coal handling systems, each transfer of the product coal after it leaves the process degrades the coal size and produces some dust. Because the SynCoal® product is dry, it does not have any inherent ability to trap small particles on the coal surfaces. This allows any dust-size particles that are generated by handling to be released and become fugitive.

In January 1995, a cooperative research project was initiated with the U.S. Bureau of Mines and the U.S. Department of Energy, to determine the effects of different processing environments and treatments on low-rank coal composition and structure. Specific objectives were to: (1) study the explosivity and flammability limits of dust from the process and (2) identify the causes of spontaneous heating of upgraded coals. Other participants in this study were the Amax Coal Company and ENCOAL, who have also experienced similar effects with their upgraded products.

Due to the handling issues, RSCP has taken a three-pronged approach to satisfying customer needs for a safe, effective way to handle SynCoal®. The first method is to employ DSE treatment, which allows conventional bulk handling for a short period (about one week) but does degrade the product heat content. The product eventually becomes dusty and susceptible to spontaneous heating again.

The second technique uses contained storage and transportation systems with pneumatic or minimal-exposure material handling systems. This technique provides maximum product quality and actually enhances the material handling performance for many industrial customers; however, transportation requires enclosed equipment and is impractical for the bulk coal handling systems of large utility customers.

The third approach is to develop a stabilization process step. SynCoal's previous work has been of great benefit in the collaborative research with ENCOAL. SynCoal hopes to incorporate its stabilization process in the next-generation facility or develop a smaller pilot operation in direct response to a specific customer requirement. Currently, a novel stabilizer unit co-developed with ENCOAL is being testing at the ACCP facility.

These approaches should allow SynCoal® to be tested in some more novel applications such as blast furnace injection systems and electric arc furnace reducing agents.

V. COMMERCIALIZATION PROSPECTS

Utility Supplemental Fuel

The utility segment is the largest and most established market for all domestic coal sales. Since the ACCP is by its nature a value-added process and the product has been determined to require special handling, unique situations must be identified where the addition of SynCoal® to the firing mix provides sufficient benefit to more than offset the increased delivered cost compared to raw western coal. These requirements have led RSCP to focus on marketing the product as a supplemental fuel in utility applications and then only to units that have specific problems with slagging or flame stability.

Utility plants with design-or fuel-related limitations such as the Milton R. Young station, J.E. Corette plant, and Colstrip Units 1 & 2 can benefit from decreased slagging, reduced SO_2 emissions, improved net generation, and reduced heat rate by burning a controlled amount of SynCoal® selectively injected into the boiler.

Industrial Fuel Opportunities

The industrial market segment is much more amenable to special handling since these customers normally receive small quantities and are much more sensitive to fuel quality issues. RSCP has developed a technique of shipments in covered hopper rail cars and/or pneumatic trucks that allows long haul distances and, when combined with inerted bin storage, provides safe and efficient handling.

SynCoal® has been found to provide superior performance in direct-fired applications, particularly as a blend with petroleum coke. SynCoal® provides good ignition and stable flame characteristics while the petroleum coke is low-cost and requires a longer burning time, expanding the processing zone. This blend of characteristics has provided a significant advantage to SynCoal®'s cement and quicklime customers. Additionally, recent tests of SynCoal®/petroleum coke blends have shown improved handling characteristics with regard to dustiness and self heating.

SynCoal® produces a gas-like flame when burned alone. In some direct-fired applications (such as road-paving asphalt plants), it can be a much lower cost option than propane, providing a small but valuable market.

Metallurgical Process Opportunities

SynCoal®'s consistent characteristics, high volatile content and high carbon content make it a good reducing agent for some metallurgical processing applications. Since low moisture content is a key characteristic for this segment, the covered hopper rail car and/or pneumatic truck delivery system is readily accepted. SynCoal® has been used successfully in ductile iron metal casting applications as a greensand binder additive due to these characteristics. RSCP has been working with a metallurgical silica producer to determine if SynCoal® is viable in their application. RSCP is continuing to pursue alternative markets in various metallurgical reduction applications and SynCoal® may even be a viable substitute for natural gas used to reduce metallurgical coke use in blast furnaces.

VI. CONCLUSION

Rosebud SynCoal has developed an advanced coal conversion process that has the potential to enhance the utility and industrial use of low-rank western subbituminous and lignite coals. SynCoal® is an ideal supplemental fuel for plants seeking to burn western low-rank coals because it allows a wider range of low-sulfur raw coals to be used to meet more restrictive worldwide emissions guidelines without derating of the units or the addition of costly flue gas desulfurization systems.

The ACCP has potential to convert inexpensive low-sulfur, low-rank coals into valuable carbon-based reducing agents for many metallurgical applications, further helping reduce worldwide emissions and decrease the U.S. dependence on foreign energy sources.

The ACCP produces a fuel which has a consistently low moisture content, low sulfur content, high heating value, and high volatile content. Because of these characteristics, SynCoal® could have significant impact on SO_2 reduction and provide a clean, economical alternative fuel to many regional industrial facilities and small utility plants, allowing them to remain competitively in operation.

However, the ACCP technology has reached a critical juncture in its development. RSCP has developed a sound plan to advance the technology further and with DOE's assistance is seeking the structure and customer commitments necessary to propel the technology into the next century.

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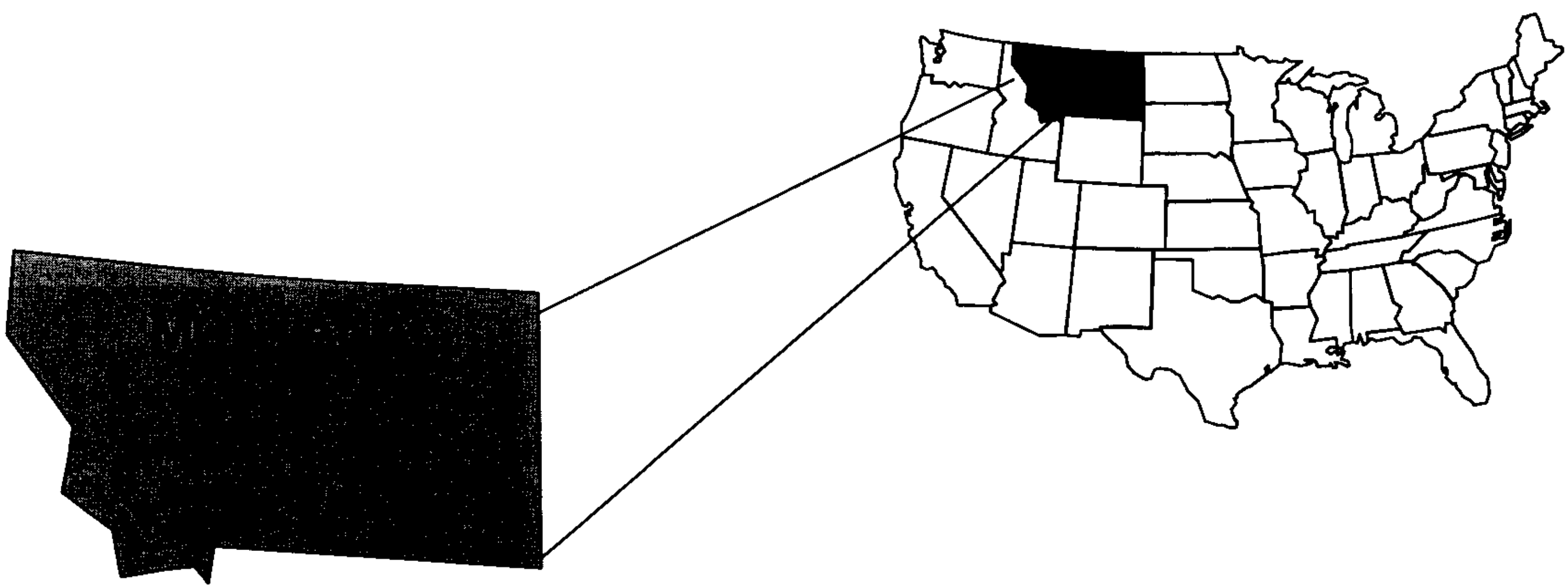
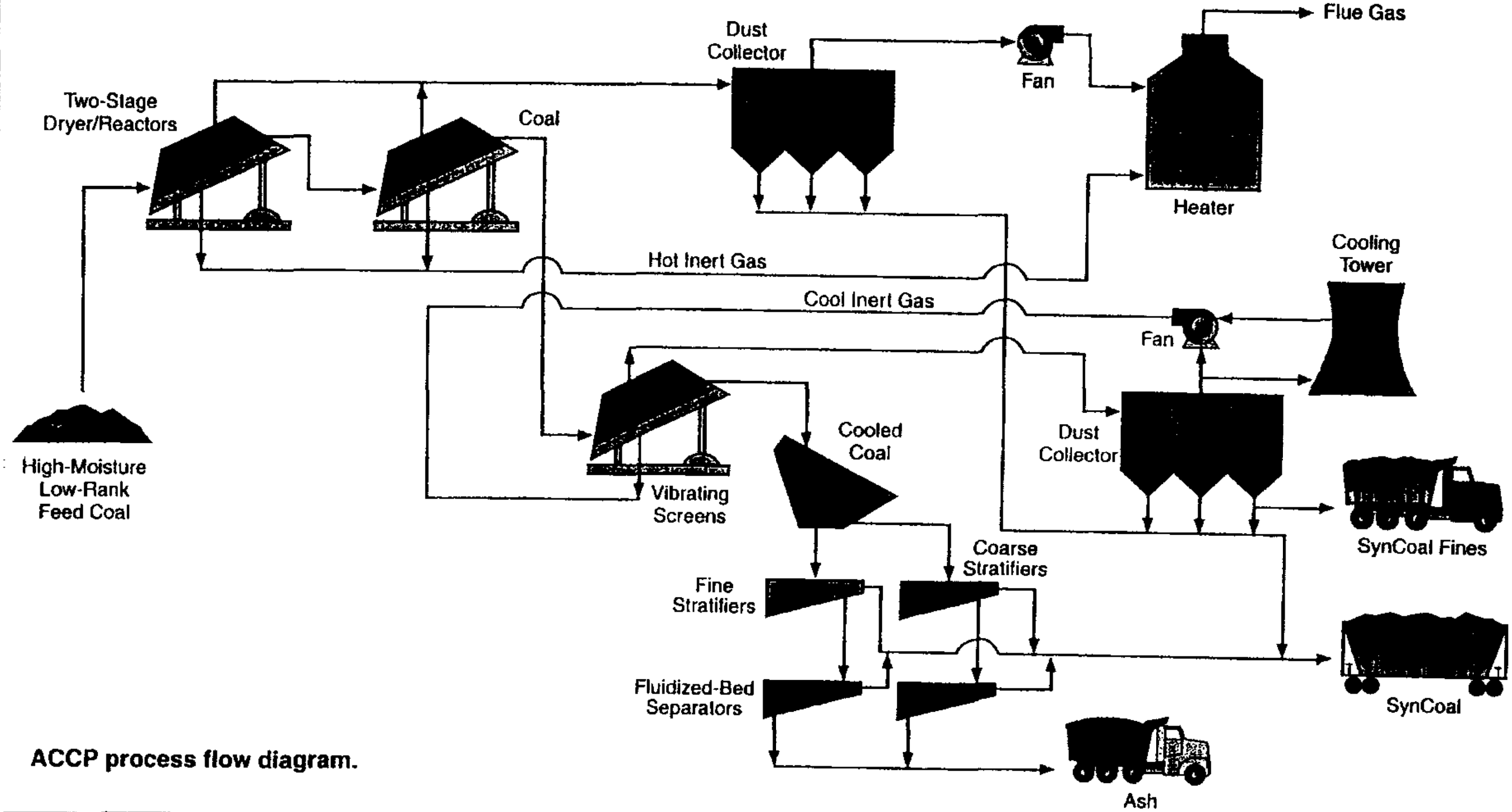
ADVANCED COAL CONVERSION PROCESS

Demo Plant Location





ACCP process flow diagram.

BLAST FURNACE
GRANULAR COAL INJECTION
SYSTEM DEMONSTRATION PROJECT

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ABSTRACT

A blast furnace coal injection system has been constructed and is being used on the furnaces at the Burns Harbor Division of Bethlehem Steel. The injection system was designed to deliver both granular (coarse) and pulverized (fine) coal. Construction was completed on schedule in early 1995. Good operational performance with low volatile coal resulted in the decision to use low volatile Virginia Pocahontas coal as the standard for granulated coal injection at Burns Harbor. The trial 1 base test on C furnace, carried out in October 1996, showed that low volatile granular coal performs very well in large blast furnaces. In addition, the furnace process can adequately handle the sulfur load from injected coal. The use of a higher ash low volatile coal during the second coal trial demonstrated that there is a coke rate disadvantage of three pounds per NTHM for each one per cent increase in coal ash at an injection rate of 260 pounds per NTHM. The higher ash coal did require a higher coke rate but had no adverse effect on the furnace permeability or productivity.

INTRODUCTION

A blast furnace coal injection system has been installed at the Burns Harbor Division of Bethlehem Steel Corporation. This is the first blast furnace coal injection system in the US that has been designed to deliver granular (coarse) coal - all previously installed blast furnace coal injection systems in the US have been designed to deliver pulverized (fine) coal. Financial assistance for the coal injection system was provided by the Clean Coal Technology Program.

The use of granular coal in blast furnaces was jointly developed by British Steel and Simon-Macawber (now CPC-Macawber) and used at the Scunthorpe Works in England. The blast furnaces at Scunthorpe have about one-half the production capability of the Burns Harbor blast furnaces. Therefore, one of the main objectives of the Clean Coal Technology (CCT) test program at Burns Harbor is to determine the effect of granular coal injection on large, high productivity blast furnaces. Another objective of the CCT test program at Burns Harbor is to determine the effect of different types of US coals on blast furnace performance.

The Burns Harbor Plant produces flat rolled sheet products for the automotive, machinery and construction markets. The Plant is located on the southern shore of Lake Michigan about 30 miles east of Chicago. Burns Harbor is an integrated operation that includes two coke oven batteries, an iron ore sintering plant, two blast furnaces, a three vessel BOF shop and two twin-strand slab casting machines. These primary facilities can produce over five million tons of raw steel per year. The steel finishing facilities at Burns Harbor include a hot strip mill, two plate mills, a cold tandem mill complex and a hot dip coating line.

When originally designed and laid-out, the Burns Harbor Plant could produce all the coke required for the two blast furnaces operating at 10,000 tons/day. However, improved practices and raw materials have resulted in a blast furnace operation that now can produce over 14,000 tons/day. Since the coke oven batteries are not able to produce the coke required for a 14,000 ton/day blast furnace output, other sources of coke and energy have been used to fill the gap. Over the years, coke has been shipped to Burns Harbor from other Bethlehem plants and from outside coke suppliers. In addition, auxiliary fuels have been injected into the furnaces to reduce the coke requirements. The auxiliary fuels have included coal tar, fuel oil and natural gas. The most successful auxiliary fuel through the 1980s and early 1990s has been natural gas. It is easy to inject and, at moderate injection levels, has a highly beneficial effect on blast furnace operations and performance. However, there are two significant problems with the use of natural gas in blast furnaces. One problem is the cost and the other is the amount that can be injected and, therefore, the amount of coke that can be replaced. Our process and economic studies showed that more coke could be replaced and iron costs could be reduced by injecting coal instead of natural gas in the Burns Harbor furnaces.

This led Bethlehem to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection at Burns Harbor. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects accepted for funding in the Clean Coal Technology Program third round of competition. The primary thrust of this project is to demonstrate commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large high productivity blast furnaces using different coals available in the US. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide the information and confidence needed by others to assess the technical and economic advantages of applying the technology to their own facilities.

A major consideration in evaluating coal injection in the US is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general inflation. Higher levels of blast furnace injectants, such as coal, enable domestic integrated steel producers to minimize their dependence on coke.

Blast Furnace Process

The ironmaking blast furnace is at the heart of integrated steelmaking operations. As shown in Figure 1, the raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300°F. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. The molten iron flows to refractory-lined ladles for transport to the basic oxygen furnaces.

A schematic showing the various zones inside the blast furnace is shown in Figure 2. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke just above the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the partially reduced ore is being melted and passes through layers of coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the high temperature properties needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 Btu/scf), it is used to heat the hot blast stoves. The excess is used to generate steam and power for other uses within the plant.

COAL INJECTION TECHNOLOGY

Bethlehem decided to utilize the CPC Macawber Blast Furnace Granular Coal Injection (BFGCI) System, because unlike more widely used systems that utilize only pulverized coal, it is capable of injecting both granular and pulverized coal. Bethlehem believes that the CPC Macawber system offers a variety of technical and economic advantages which make this system potentially very attractive for application in the US basic steel industry. A schematic showing the application of the technology to the blast furnace is shown in Figure 3. Some of the advantages of this technology include:

- The injection system has been used with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes. Granular coal is 10-30% minus 200 mesh whereas pulverized coal is 70-80% minus 200 mesh.

- The costs for granular coal preparation systems are less than those for the same capacity pulverized coal systems.

- Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.

- Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.

- System availability has exceeded 99% during several years of operation at British Steel.

- The unique variable speed, positive displacement CPC Macawber injectors provide superior flow control and measurement compared to other coal injection systems.

The joint development by British Steel and CPC Macawber of a process for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary blast furnace at the Scunthorpe Works. (1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the CPC Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig led Bethlehem to conclude that the system could be applied successfully to large blast furnaces using domestic coals.

INSTALLATION DESCRIPTION

A simplified flow diagram of the coal handling system at Burns Harbor is shown in Figure 4. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility delivers the prepared coal to the blast furnace tuyeres.

Raw Coal Handling. Coal for this project is transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal is unloaded using a railroad car dumper, which is part of the blast furnace material handling system. A modification to the material handling system was made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

Raw Coal Reclaim. The raw coal reclaim tunnel beneath the coal storage pile contains four reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, feed a conveyor in the tunnel. The reclaim conveyor transports the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator is located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor discharges the coal onto a vibrating screen to separate coal over 2 inches from the main stream of minus 2-inch coal. The oversized coal passes through a precrusher which discharges minus 2-inch coal. The coal from the precrusher joins the coal that passes through the screen and is conveyed from ground level by a plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

Coal Preparation. The plant feed conveyor terminates at the top of the process building that houses the Coal Preparation Facility. Coal is transferred to a distribution conveyor, which enables the coal to be discharged into either of two raw coal storage silos. The raw coal silos are cylindrical with conical bottoms and are completely enclosed with a vent filter on top. Each silo holds 240 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons are located in the conical section to loosen the coal to assure that mass flow is maintained through the silo.

Coal from each raw coal silo flows into a feeder which controls the flow of coal to the preparation mill. In the preparation mill, the coal is ground to the desired particle size. Products of combustion from a natural gas fired burner are mixed with recycled air from the downstream side of the process and are swept through the mill grinding chamber. The air lifts the ground coal from the mill vertically through a classifier where oversized particles are circulated back to the mill for further grinding. The proper sized particles are carried away from the mill in a 52-inch diameter pipe. During this transport phase, the coal is dried to 1-1.5% moisture. The drying gas is controlled to maintain oxygen levels below combustible levels. There are two grinding mill systems; each system produces 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

The prepared coal is then screened to remove any remaining oversize material. Below the screens, screw feeders transport the product coal into one of four 180-ton product storage silos and then into a weigh hopper in two-ton batches. The two-ton batches are dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility.

Coal Injection. The Coal Injection Facility includes four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg feeds an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal is mixed with high-pressure air and is carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on each of the 28 blowpipes at each furnace. At the injection lance tip, the coal is mixed with the hot blast and carried into the furnace raceway. The 14 injectors at the bottom of the distribution bin feed alternate furnace tuyeres. Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin and 14 injector systems.

PROJECT MANAGEMENT

The demonstration project is divided into three phases:

Phase I	Design
Phase II	Construction and Start-up
Phase III	Operation and Testing

Phase I was completed in December 1993 and construction was completed in January 1995. Coal was first injected in four tuyeres of D furnace on December 18, 1994. The start-up period continued to November 1995 at which time the operating and testing program started. The testing of coals (Phase III) is expected to continue to late 1998.

The estimated project cost summary is shown in Table IA. The total cost is expected to be about $191 million. Additional information on project management was presented at the previous CCT Conference. (3,4) Project milestone dates are noted in Table IB.

Facility Start-Up

The coal injection facilities were fully started in January 1995 and by early June the coal injection rate on both furnaces had stabilized at 140 lbs/ton. There were facility start-up problems in January and February, but by mid-year the coal preparation and delivery systems were operating as designed. The injection rate on C furnace was increased through the summer months and was over 200 pounds/NTHM for September, October and November. The injection rate on D furnace was kept in the range of 145-150 pounds/NTHM during the second half of the year.

In December 1995, severe cold weather caused coal handling and preparation problems that were not experienced during start-up in early 1995. The most severe problem was due to moisture condensing on the inside walls of the prepared coal silos. The moisture caked the coal and eventually blocked the injectors below the silos. As a result, coal injection on C furnace was stopped in mid-December and the coal silos were emptied and cleaned. In order to prevent condensation in the future, the top and sides of the C furnace coal silos were insulated. The D furnace silos were insulated in January 1996. The insulation has prevented any recurrence of blocked injectors due to caked coal.

The start-up operation was conducted with a high volatile coal from eastern Kentucky with 36% volatile matter, 8% ash and 0.63% sulfur. The coal preparation system was operated to provide granular coal throughout the start-up period. Figure 5 shows the history and progression of injected coal and coke rates since the start-up with high volatile coal. January 1995 through September 1995 shows an average injected coal rate of less than 100 pounds/NTHM with a furnace coke rate in excess of 780 pounds/NTHM. Since the switch to a low volatile coal in October 1995, the injected coal rate has increased dramatically and the furnace coke rate is much lower.

PROJECT TEST PLAN

The objective of the test program is to determine the effect of coal grind and coal type on blast furnace performance. A trial will be conducted to determine the effect of using pulverized coal with a nominal size of 80% minus 200 mesh. The results of this trial will be of great interest to blast furnace operators and could have a significant effect on the type of coal injection facilities that will be installed in the future.

Other trials will be conducted to determine the effect of coal types and coal chemistry on furnace performance. The important furnace performance parameters that will be closely monitored during these trials are coke rate, raw material movement in the furnace, pressure drop in the furnace, gas composition profiles, iron analyses and slag analyses. All results of the blast furnace trials will be evaluated and documented in a comprehensive report.

Two specific trials have been completed since the start-up. A base period evaluation using low volatile coal was completed and documented in late 1996. The second trial was completed during June 1997 to assess the use of a higher ash low volatile coal.

Our expectation during 1998 is to complete a trial comparing granulated coal to pulverized coal. In addition, we are considering the use of a high volatile, western coal, perhaps from Colorado, for a trial period. We are also considering repeating the operational experience with the high volatile coal that was used during the initial coal injection start-up.

BASE PERIOD TRIAL RESULTS WITH LOW VOLATILE COAL

Meaningful analysis of blast furnace process changes that occur with a change of injected coal type or sizing requires a base test period for comparison with future tests. The Burns Harbor C furnace operation during October 1996 meets the requirements for an acceptable base period. The operating results for this period may be used as the basis for the evaluation of future trials.

The October operation on C furnace was adequate in terms of furnace performance with coal injection. The injection facility supplied coal without interruption for the entire month. The average coal rate of 264 pounds/NTHM varied from 246-278 pounds/NTHM on a daily basis. The furnace coke rate during the period averaged 661 pounds/NTHM.

The key operating parameters for the base test are shown in Table II. These values comprise the operating comparative base results necessary for future trial evaluation.

The type of coal used and the grind size distribution for the trial is of primary consideration for this period. The monthly average chemistry for the Virginia Pocahontas injected coal is shown on Table III. This coal is a low volatile with high carbon and relatively low ash content. These two characteristics provide a high coke replacement value for the operation.

The sizing of the granulated coal product is also important to the blast furnace operators. Daily samples are taken to determine the size distribution of the coal sent to the furnace. Table III shows the average size distribution of the coal injected in C furnace for October. The coal injected in C furnace was about 15% -200 mesh for the month.

The injected coal rate of 264 pounds/NTHM on C furnace during October is one of the highest achieved since the start-up of the coal facility. The reliability of the coal system enabled the operators to reduce furnace coke to a low rate of 661 pounds/NTHM. The low coke rate is not only good economically, it is an indicator of the efficiency of the furnace operation with regard to displacing coke with injected coal.

Hot metal chemistry, particularly silicon and sulfur content, is another important ironmaking parameter. The end user of the molten iron, the Steelmaking Department, specifies the silicon and sulfur levels that are acceptable for their process. Low variability around the average value is necessary to achieve these specifications. The standard deviations of the silicon and sulfur content of the hot metal for October are shown on Table II.

Table II also shows a typical period of natural gas injection on the C furnace during January 1995. Comparatively, we can see the significant operating changes that occur with the use of injected coal versus natural gas. The wind volume on the furnace has decreased significantly with the use of coal. Oxygen enrichment also increased from 24.4% to 27.3% with coal. The amount of moisture added to the furnace in the form of steam increased most significantly from 3.7 grains/SCF of wind to 19.8 grains/SCF. All of these operating variables were increased by the furnace operating personnel to maintain adequate burden material movement. These actions also increased the permeability of the furnace burden column. Permeability is discussed in more detail later.

Also of significance in Table II is the adjustment made to the furnace slag chemistry to accommodate the increased sulfur load from the injected coal. The sulfur content of the slag increased from 0.85% with gas to 1.39% with coal. The slag volume was increased in order to help with the additional sulfur input.

Blast furnace slag chemistry and volume is a determining factor in the final sulfur content in the hot metal. The blast furnace slag must be of such a chemistry that it can carry the sulfur supplied by the burden material, including the sulfur contributed by the injected coal. Table

IV shows the sulfur balance on C furnace during the month of October. Injected coal is the second largest contributor of sulfur to the blast furnace process. Most of the sulfur is removed by the blast furnace slag.

The blast furnace also produces large quantities of gas. The gas exits the top of the furnace, is cleaned and used as a fuel in the hot blast stoves. The excess gas produced is consumed in generating steam. Special testing during October for the presence of sulfur in the gas shows an average of 3.1 grains per 100 scf during the month. The amount of sulfur present in the gas and the total gas production is shown on Table IV. The total furnace sulfur balance shows a furnace sulfur input to output closure of 99.2%.

A method of representing furnace stack conditions as well as the overall furnace operation is through the use of a calculated permeability. Permeability is a function of the blast rate and the pressure drop through the furnace. The equation used for this purpose is:

$$\text{Permeability} = (\text{Furnace Wind Rate})^2 / [(\text{Furnace Blast Pressure})^2 - (\text{Furnace Top Pressure})^2]$$

The larger the permeability value the better the furnace burden movement and the better the reducing gas flows through the furnace column. Figure 6 is a plot of the permeability value and the injected coal rate for each month in 1996. The permeability decreased from January to February as the injected coal rate was increased. Since then, this value has increased monthly, declining only slightly to a level of 1.19 for October. This indicates an acceptable overall operation on the C furnace during the base period.

HIGHER ASH COAL TRIAL

Trial Coal Selection

During the entire year of 1996 the injection coal used on both furnaces was the low volatile, high carbon content Buchanan/Virginia Pocahontas. The coal comes from two different mine sites, however, both coals are from the same seam and are very similar chemically.

The typical analysis of Virginia Pocahontas in October 1996 and the Buchanan coal used on the furnaces immediately prior to the trial period is shown in Table V. For a trial to assess ash content only, it was important to use a coal that varies only in ash so that there would be no confounding issues such as sulfur content or large differences in volatile matter. To achieve this, the supplier of the Buchanan coal suggested that ash content could be increased at the mine site cleaning plant if one of the usual coal cleaning steps was eliminated. Trials were run at the mine and subsequent coal analysis confirmed that the ash content could be increased by this method. The average analysis of the four train trial coal is also shown on Table V. The trial coal is 2.4% higher in ash than the coal used for the October 1996 base and is 3.0% higher in ash than the coal used during the furnace period immediately prior to the trial. As demonstrated on Table V, the three operating periods were run with coal that is significantly different only in ash content.

Also shown in Table V is the average size distribution of the coal during the trial period. As during the October base period, the granular coal was about 15% -200 mesh.

C Furnace Operations

The primary concern of the furnace operators, both before and during a blast furnace trial, is to maintain a consistent operation so that a valid comparative analysis of the trial variable can be made. Table VI shows the operating results for the high ash trial period on C furnace and the two operating periods that are used to make the comparative analysis.

Each of these periods is operationally similar: the amount of injected coal used during each period is about the same; the general blast conditions during the periods are comparable; the wind rates only vary from 135,370 SCFM to 137,000 SCFM; and blast pressure, top pressure and moisture additions are comparable.

General Trial Observations

There were several operating variables that were of concern and were closely observed by the operators during the trial . Several of these parameters could have adversely affected furnace performance with the use of the high ash coal. However, the trial period confirmed that high coal ash, at the injection rate used, did not hinder furnace performance. This finding is based on data in Table VI which shows the following:

1. Furnace permeability was not changed and a higher coal ash did not have a deleterious effect in the raceway.

2. Furnace blast pressure and wind volume were maintained at the base conditions during the trial.

3. Furnace production rates were up as delay periods declined during the trial.

4. Hot metal silicon and sulfur content and variability were about the same during all three periods.

The primary change in the operation, as expected, was the increase in the blast furnace slag volume. The 461 pounds/NTHM slag volume during the trial is higher than the 448 pounds/NTHM slag volume during the May 1 - May 27, 1997 period and the 424 pounds/NTHM during the October 1996 period. The general conclusion is that higher ash content in the injected coal can be adjusted by the furnace operators and does not adversely affect overall furnace operations.

Furnace Coke Rate Results

The primary reason for this coal trial was to determine the coke rate penalty to the blast furnace that results from the use of higher ash injection coal. In order to assess the comparative furnace coke rate during a trial, all of the blast furnace variables that affect the furnace coke rate that are different from the base must be adjusted by using coke correction factors. The only variables that are not corrected or adjusted are those affected by the operating variable that is being assessed. After all of the operational coke differences between the base period and the trial period are accounted for, the remaining coke is attributed to the variable being studied. Since the higher ash coal causes an increase in the furnace slag volume and does contribute to higher furnace coke usage, we have not adjusted the coke for changes in the slag volume.

Three comparisons, using the above logic, were made to validate and substantiate the results of this trial. The high ash trial results were compared to the period immediately prior to the trial; the previously documented base period results from October 1996; and a previously completed study on the coke replacement characteristics of low volatile coals. The latter study was conducted using Burns Harbor C and D monthly average operating data for 1996 with low volatile coal.

The results of the first comparison are shown in Table VII where the high ash trial data has been corrected to the May 1 - May 27,1997 base period. The largest coke rate adjustment necessary is for the difference in the injected coal amount of seven pounds of coke. The conclusion from this table is that a 3% increase in injected coal ash results in a nine pound/NTHM increase in the furnace coke rate. This is the amount of coke carbon needed to replace the carbon from the high ash coal without an additional process penalty.

The values from the second comparative period are shown in Table VIII. As with the previous analysis, only small adjustments are required to establish the overall corrected coke rate. This comparison substantiates the first results. The 2.4% increase in coal ash from the October 1996 base period to the trial period results in a coke penalty of eight pounds/NTHM.

In Figure 7, the coal injection and furnace coke rates for the trial are compared to those on both C and D furnace during 1996. As noted previously, there was a coke rate increase on C furnace during the trial period. The coke rate adjustments which include the trial data in this figure are documented in Table IX.

The blast furnace sulfur balance for the trial period is shown in Table X. There is good closure for the sulfur input and output.

The base period coal trial with low volatile coal demonstrated that:

- Low volatile, granular coal performs very well in large blast furnaces.

- The furnace process can adequately handle the increased sulfur loading from the injected coal.

- The decrease in furnace permeability as a result of coal injection can be minimized by increasing oxygen enrichment and raising blast moisture additions to the furnace.

The higher ash coal trial demonstrated some important blast furnace operating considerations when using a high ash coal:

- There is a coke rate disadvantage of three pounds per NTHM for each 1% increase of ash in the injection coal at an injection rate of 260 pounds per NTHM.

- Higher ash coal had no adverse effect on the furnace permeability.

- The productivity of the furnace was unaffected by the 3% increase in coal ash at the injection rate of 260 pounds per NTHM.

- Hot metal quality was unaffected by the increased ash content of the injection coal.

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3. D Kwasnoski and L. L. Walter, "Blast Furnace Granular Coal Injection," Second Annual Clean Coal Technology Conference, Atlanta, GA, September 1993.

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6. Bethlehem Steel Corporation, January 1 - December 31, 1996, "DOE Annual Report on the Blast Furnace Granular Coal Injection Project."

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FIGURE 1

THE BLAST FURNACE COMPLEX

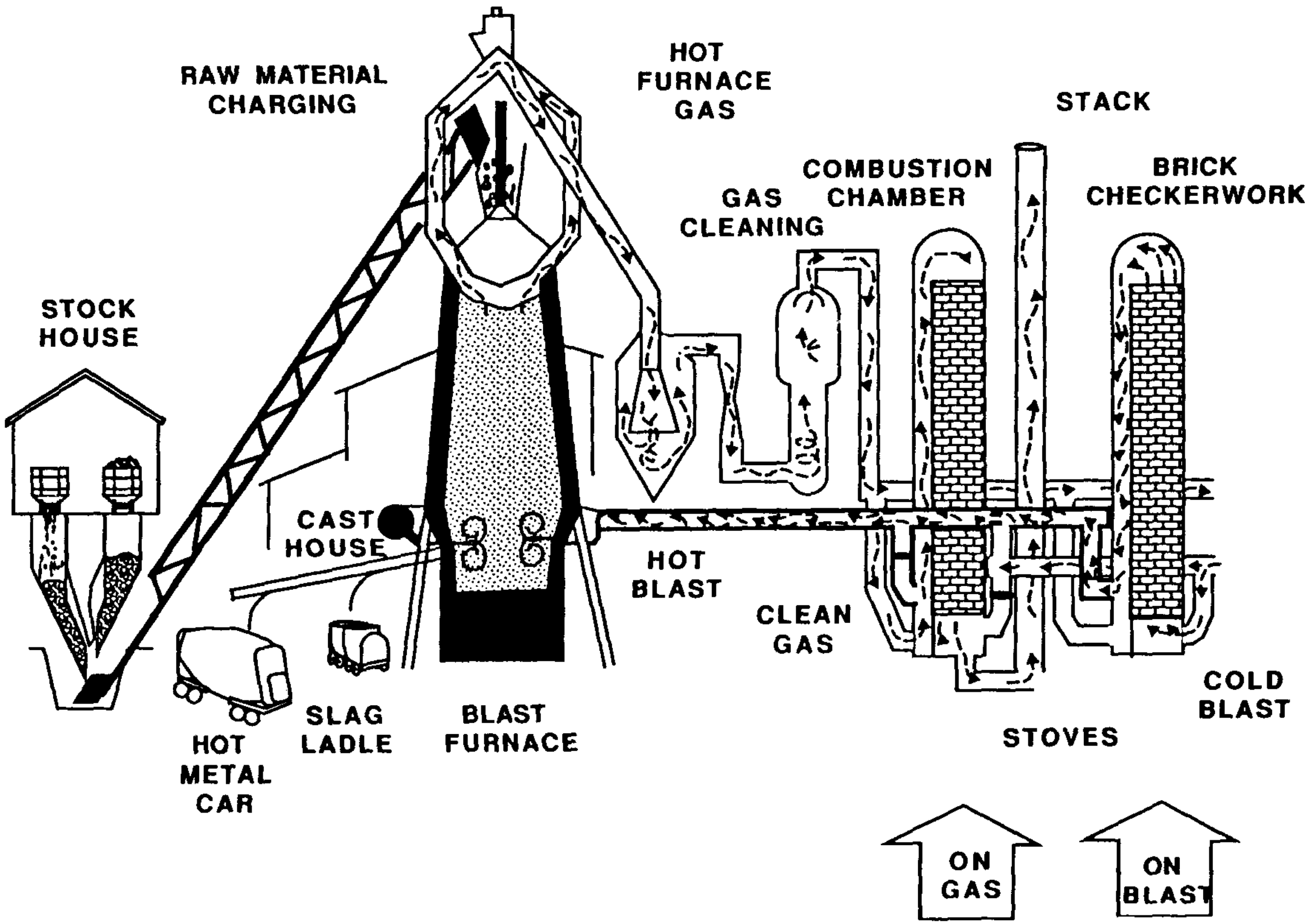


FIGURE 2

ZONES IN THE BLAST FURNACE

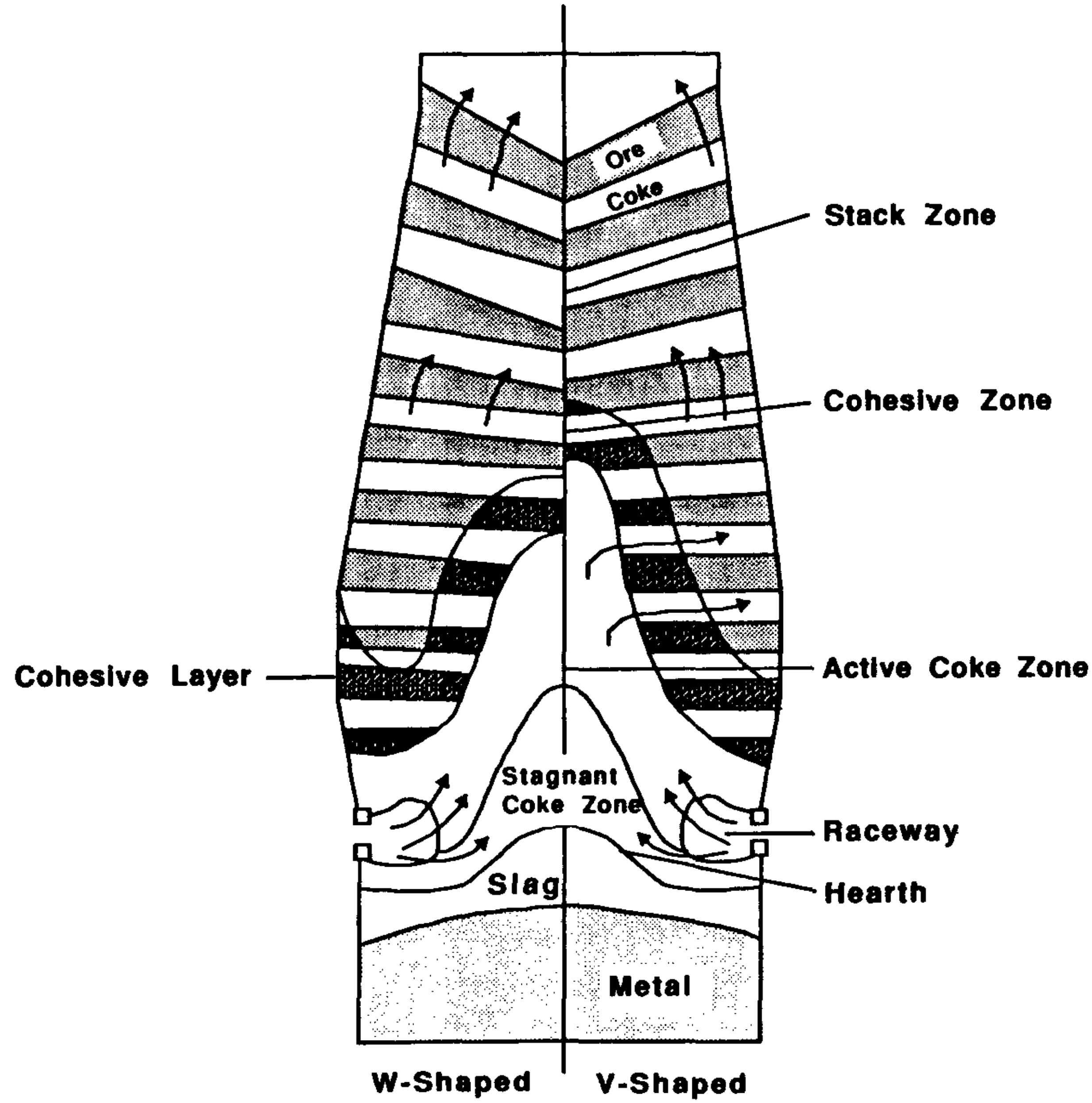


FIGURE 3

APPLICATION OF COAL INJECTION

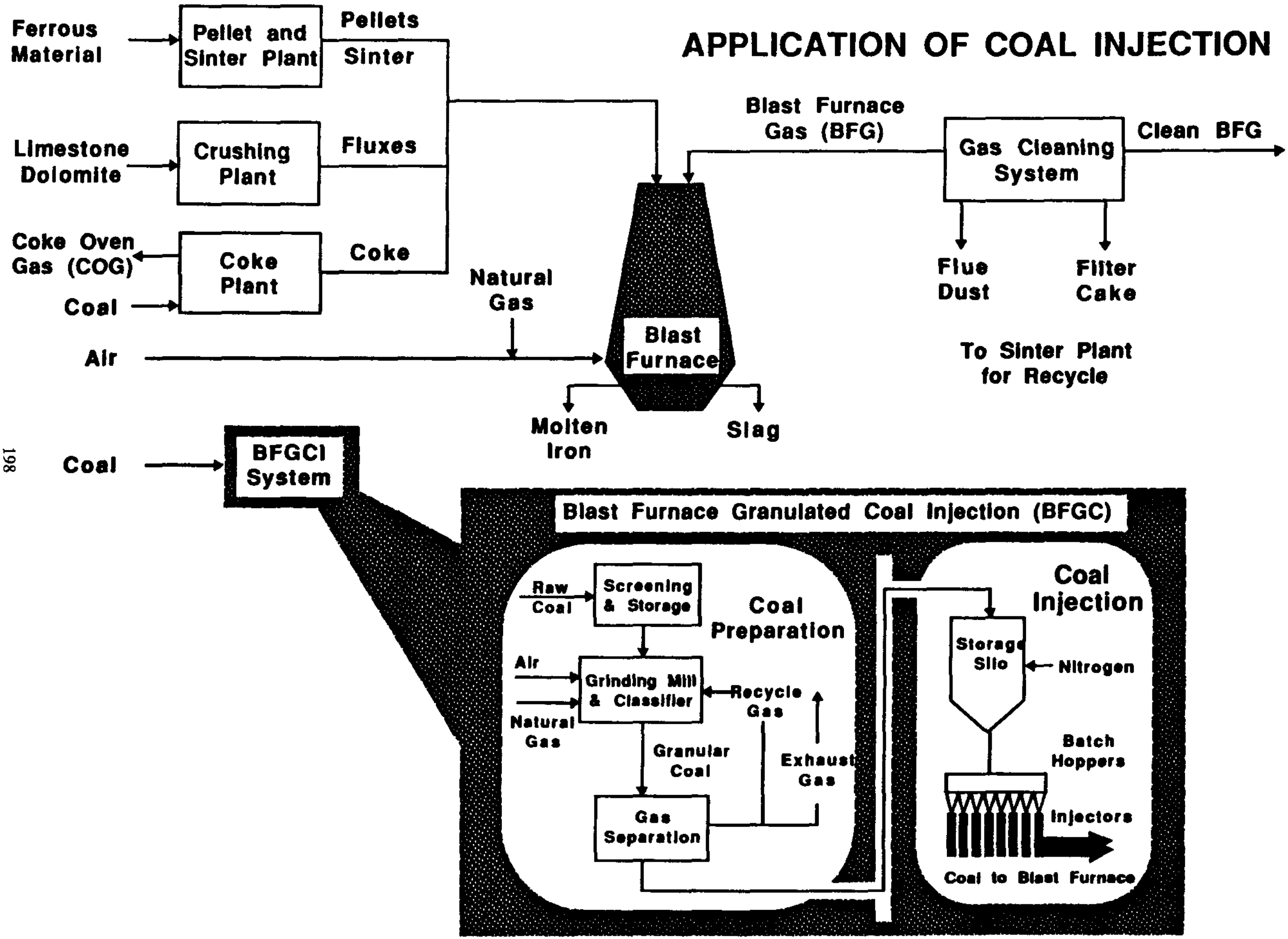


FIGURE 4. COAL PREPARATION AND INJECTION FACILITIES BURNS HARBOR PLANT

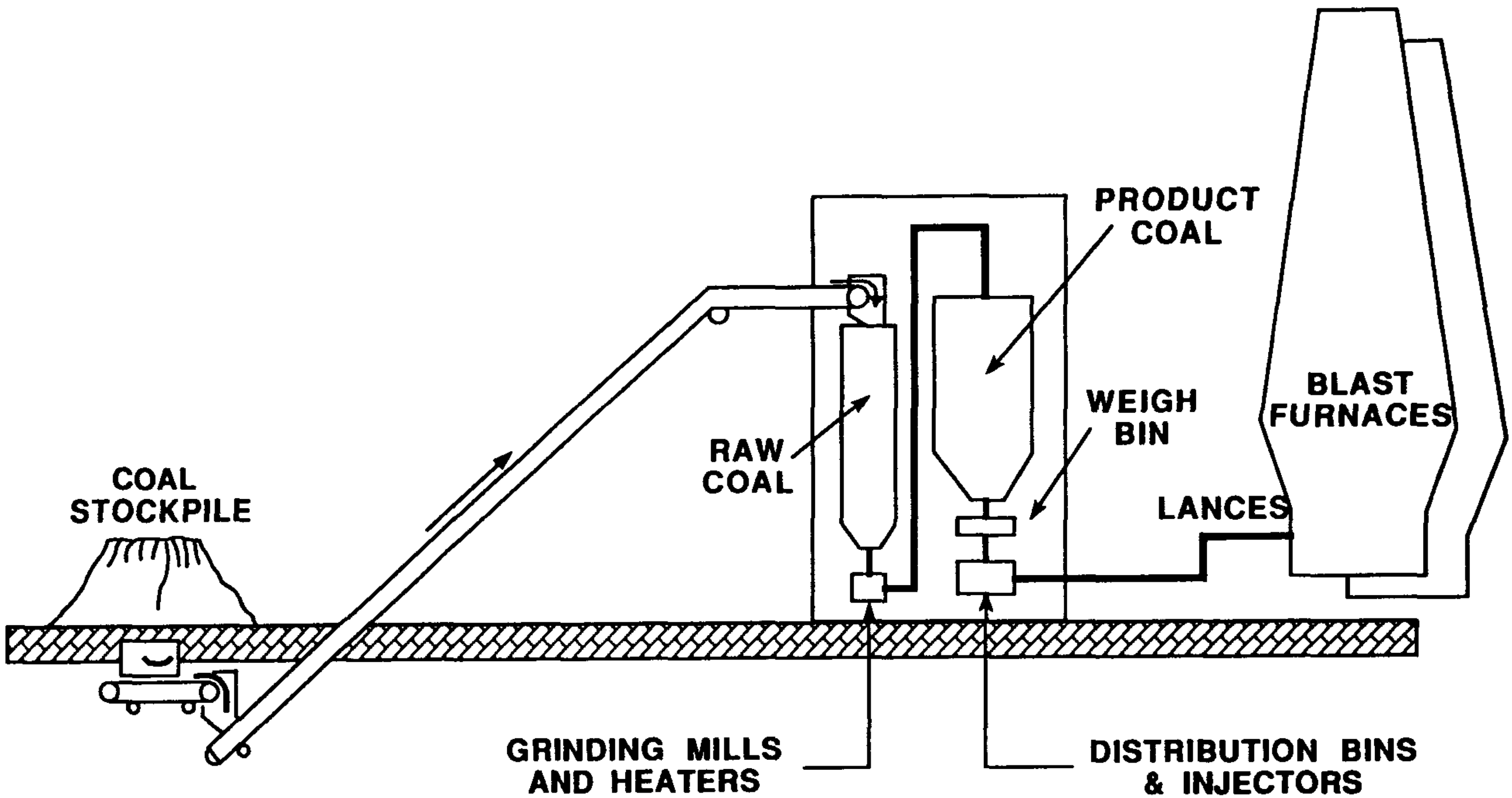
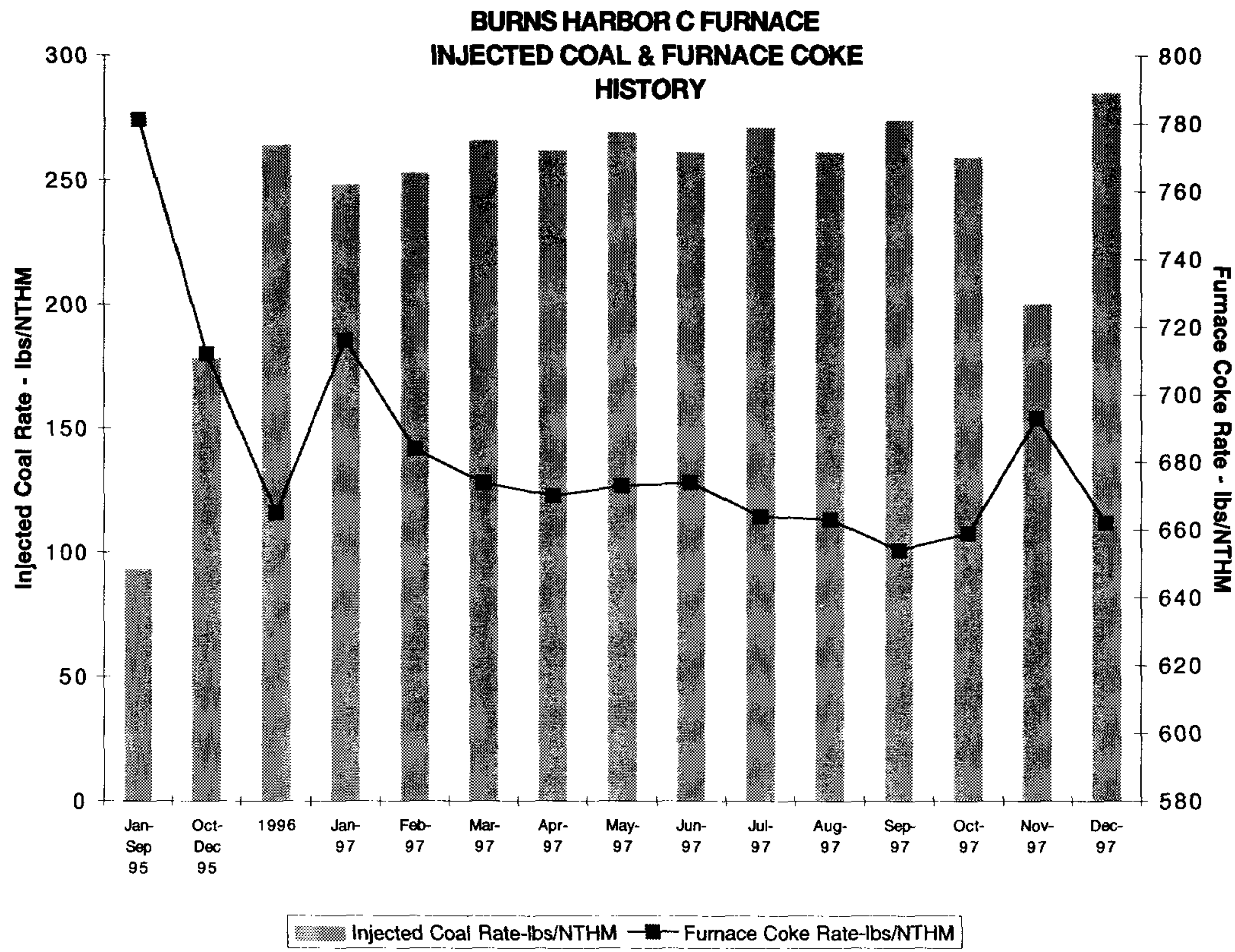


FIGURE 5



BURNS HARBOR C FURNACE
INJECTED COAL & FURNACE COKE
HISTORY
Injected Coal Rate - lbs/NTHM
300
250
200
150
100
50
0
Furnace Coke Rate - lbs/NTHM
800
780
760
740
720
700
680
660
640
620
600
580
Jan-Sep 95
Oct-Dec 95
1996
Jan-97
Feb-97
Mar-97
Apr-97
May-97
Jun-97
Jul-97
Aug-97
Sep-97
Oct-97
Nov-97
Dec-97
Injected Coal Rate-lbs/NTHM
Furnace Coke Rate-lbs/NTHM

FIGURE 6

BURNS HARBOR C FURNACE - PERMEABILITY & INJECTED COAL RATE

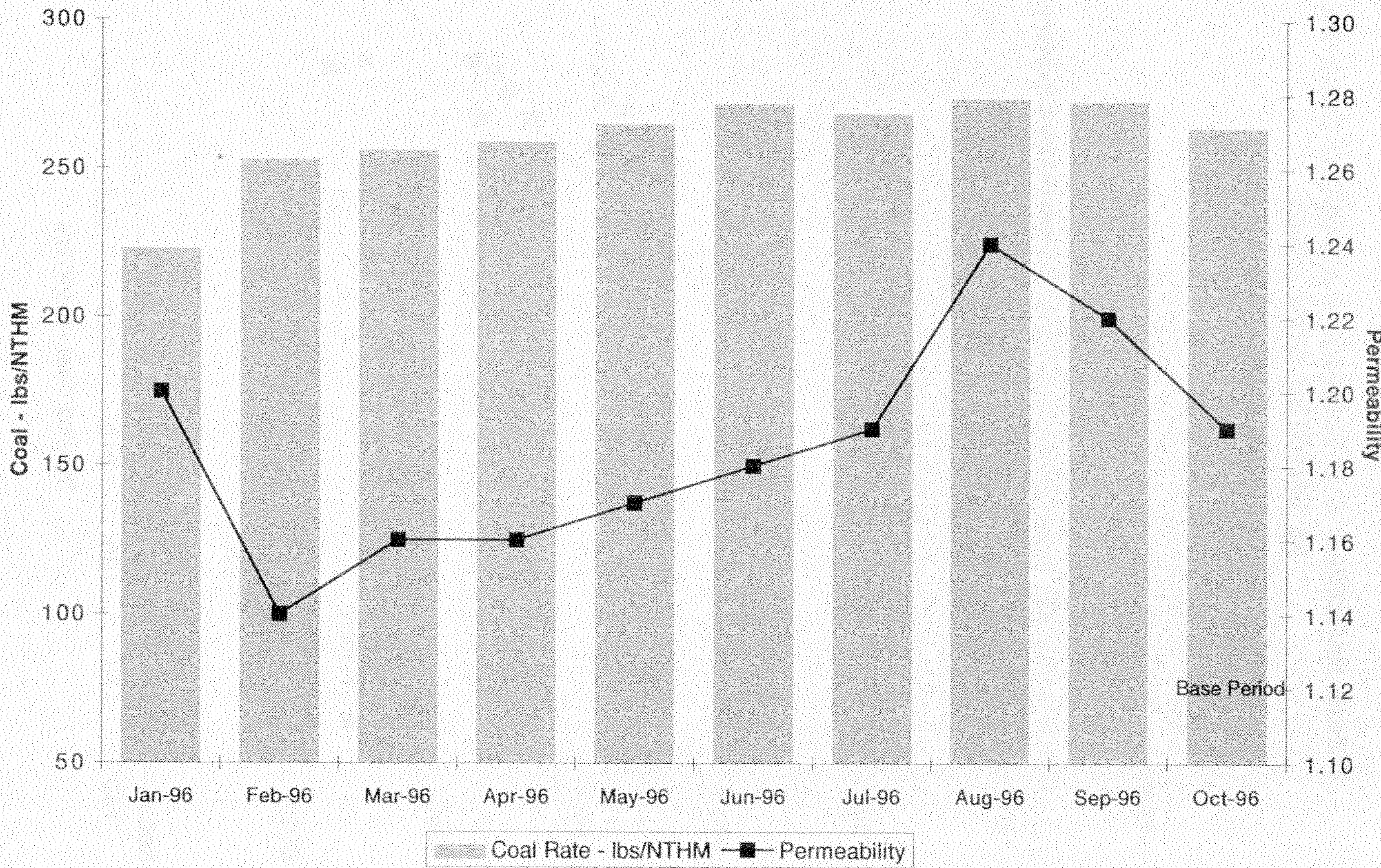


FIGURE 7

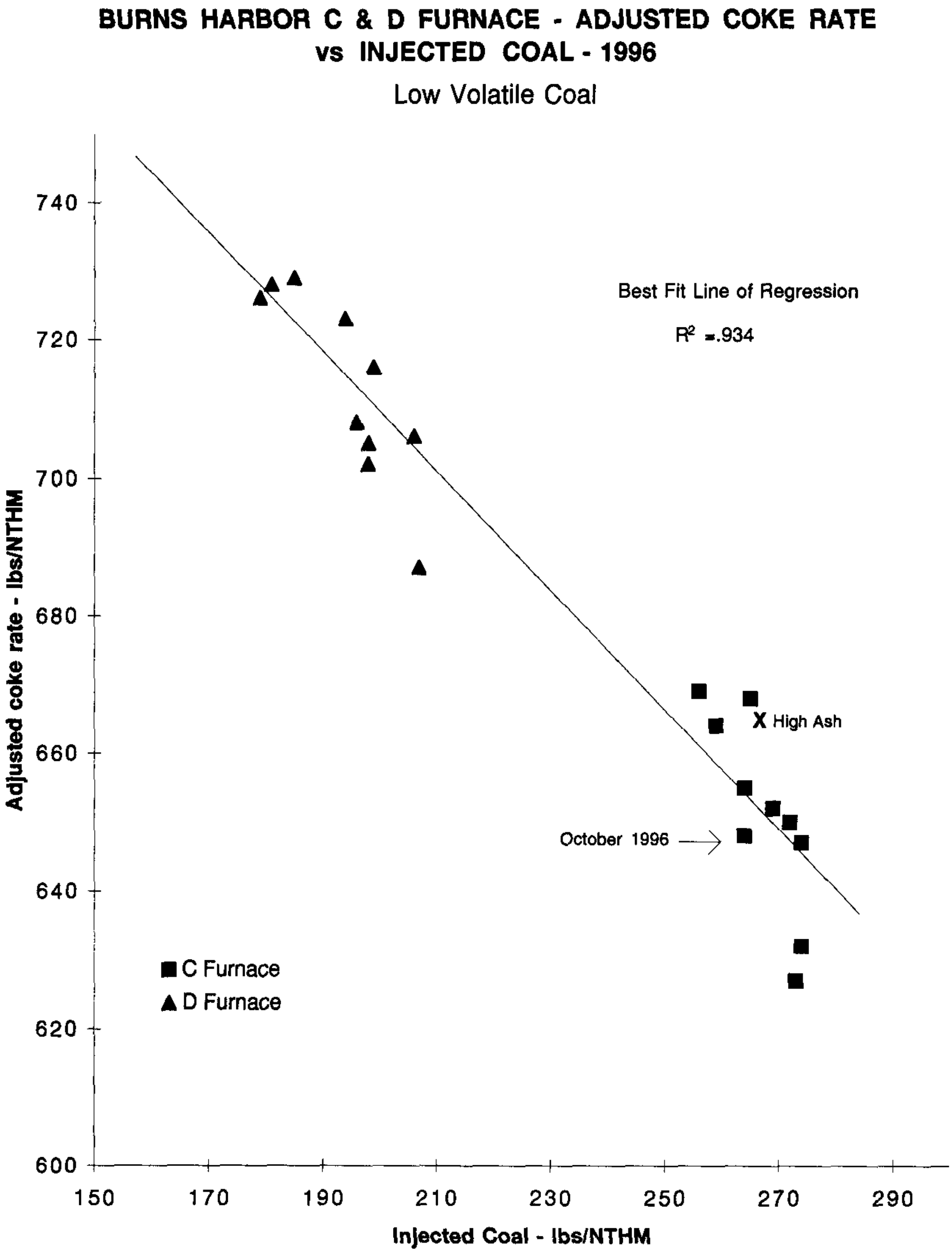

BURNS HARBOR C & D FURNACE - ADJUSTED COKE RATE
vs INJECTED COAL - 1996
Low Volatile Coal
Best Fit Line of Regression
R² =.934
X High Ash
October 1996
C Furnace
D Furnace
Adjusted coke rate - lbs/NTHM
Injected Coal - lbs/NTHM
740
720
700
680
660
640
620
600
150
170
190
210
230
250
270
290

TABLE IA

ESTIMATED GRANULAR COAL INJECTION PROJECT COST SUMMARY

	$ Million	
Phase I Design	5.19	
Phase II Construction and Start-Up	133.85	
Phase III Operation	51.61	
Total Cost	190.65	
Cost Sharing		
DOE	31.26	(16.4%)
Bethlehem Steel	159.39	(83.6%)
	190.65	

TABLE IB

PROJECT MILESTONE DATES

Begin Detailed Construction Engineering	April 1, 1993
Received State Environmental Construction Permit	August 4, 1993
Start Construction	August 31, 1993
90% Design Review	January 12, 1994
50% Construction Review	June 1994
100% Construction Review	December 1994
Begin Coal Testing Demonstration	November 1995
Complete Coal Testing Demonstration	July 1998

TABLE II

BASE PERIOD EVALUATION
Burns Harbor C Furnace
Summary of Operations

	OCTOBER 1996	JANUARY 1995
Production, NTHM/day	6943	7436
Delays, Min/day	71	25
Coke Rate, lb/NTHM Rep.	661	740
Natural Gas Rate, lbs/NTHM	0	141
Injected Coal Rate, lbs/NTHM	264	0
Total Fuel Rate, lbs/NTHM	925	881
Burden %:		
Sinter	35.9	32.3
Pellets	63.8	67.0
Misc.	.3	.7
BOF Slag, lbs/NTHM	5	0
Blast Conditions:		
Dry Air, SCFM	137,005	167,381
Blast Pressure, psig	38.8	38.9
Permeability	1.19	1.57
Oxygen in Wind, %	27.3	24.4
Temp, F	2067	2067
Moist., Grs/SCF	19.8	3.7
Flame Temp, F	3841	3620
Top Temp, F	226	263
Top Press, psig	16.9	16.1
Coke:		
H2O, %	5.0	4.8
Hot Metal %:		
Silicon	.50	.44
Standard Dev.	.128	.091
Sulfur	.040	.043
Standard Dev.	.014	.012
Phos.	.072	.070
Mn.	.43	.40
Temp., F	2734	2745
Slag %:		
SiO2	36.54	38.02
Al2O3	9.63	8.82
CaO	39.03	37.28
MgO	11.62	12.02
Mn	.46	.45
Sulfur	1.39	0.85
B/A	1.10	1.05
B/S	1.39	1.30
Volume, lbs/NTHM	424	394

TABLE III

BURNS HARBOR C FURNACE INJECTED COAL ANALYSIS AND SIZING OCTOBER 1996-COAL TEST BASE

Coal	Va. Pocahantas October 1996
Vol. Matter, %	18.00
C(%)	87.1
O(%)	1.23
H2(%)	4.2
N2(%)	1.21
Cl(%)	.170
Ash, %	5.3
Total Mois.,%	6.6
Sulfur, %	.78
GHV, BTU/lb (dry)	14974
HGI	100
Phos. (P2O5),%	.005
Alkali, % (Na2O+K2O)	.156
SiO2 (%)	2.20
Al2O3 (%)	1.25
CaO (%)	.39
MgO (%)	.09

C FURNACE PRODUCT COAL SIZING OCTOBER 1996

		MEAN %	CUM %
+4 Mesh		0	
-4 Mesh	+ 8 Mesh	0.6	0.6
-8 Mesh	+16 Mesh	3.7	4.3
-16 Mesh	+30 Mesh	10.6	14.9
-30 Mesh	+50 Mesh	16.0	30.9
-50 Mesh	+100 Mesh	26.8	57.7
-100 Mesh	+200 Mesh	27.7	85.4
-200 Mesh	+325 Mesh	13.9	99.3
-325 Mesh		0.70	100.0
TOTAL		100.0	

TABLE IV

BURNS HARBOR C FURNACE SULFUR BALANCE
OCTOBER 1996 - COAL TEST BASE

SULFUR INPUT:	October 1996	**SULFUR OUTPUT:**	October 1996
Material;		Material;	
Furnace Coke, Sulfur Analysis	.69%	Blast Furnace Slag, Sulfur Analysis	1.39%
Tons Coke Used	71,085.0	Total Tons Produced	45,626.6
Tons Sulfur In	490.5	Tons Sulfur Out	634.2
Injected Coal, Sulfur Analysis	.78%	Blast Furnace Iron, Sulfur Analysis	.040%
Tons Coal Used	28,409.0	Total Tons Produced	215,220.0
Tons Sulfur In	221.6	Tons Sulfur Out	86.1
Sinter, Sulfur Analysis	.02%	Flue Dust, Sulfur Analysis	.450%
Tons Sinter Used	121,282.6	Total Tons Produced	1,076.1
Tons Sulfur In	24.3	Tons Sulfur Out	4.8
Pellets, Sulfur Analysis	.01%	Filter Cake, Sulfur Analysis	.482%
Tons Pellets Used	215,306.5	Total Tons Produced	2,570.60
Tons Sulfur In	21.5	Tons Sulfur Out	12.4
Scrap, Sulfur Analysis	.23%	Top Gas, Sulfur Content	3.1 Grs./100 scf
Tons Scrap Used	3,981.7	Total Gas Produced, MMCF	108,246
Tons Sulfur In	9.2	Tons Sulfur Out	23.9
BOF Slag, Sulfur Analysis	.07%		
Tons BOF Used	530.2		
Tons Sulfur In	.4		
TOTAL TONS of SULFUR IN:	**767.5**	TOTAL TONS of SULFUR OUT:	**761.4**
		SULFUR OUT/SULFUR IN	**.992**

TABLE V

INJECTION COAL ANALYSIS
BURNS HARBOR HIGH ASH COAL TRIAL

Coal	Va. Pocahontas October 1996	Buchanan 6 Train Average Prior to Trial	High Ash Buchanan 4 Train Trial Average
Volatile Matter, %	18.00	19.79	18.75
Sulfur, %	.78	.82	.75
Ash, %	**5.30**	**4.72**	**7.70**
Ultimate Analysis, %			
Carbon	87.10	87.04	84.32
Oxygen	1.23	1.94	2.24
Hydrogen	4.20	4.27	3.88
Nitrogen	1.21	1.21	1.12
Chlorine	.170	.140	.120
Total Moisture, %	5.30	6.77	6.46
GHV, BTU/lb (dry)	14974	15086	14425
Ash Analysis, %			
SiO2	41.50	32.39	41.69
Al2O3	23.58	22.76	23.33
CaO	7.36	10.10	8.27
MgO	1.69	2.05	1.75

C FURNACE PRODUCT COAL SIZING
May 28 - June 23, 1997

		MEAN %	CUM %
+4 Mesh		0	
-4 Mesh	+8 Mesh	.3	0.3
-8 Mesh	+16 Mesh	1.8	2.1
-16 Mesh	+30 Mesh	7.4	9.5
-30 Mesh	+50 Mesh	15.1	24.6
-50 Mesh	+100 Mesh	27.0	51.6
-100 Mesh	+200 Mesh	34.0	85.6
-200 Mesh	+325 Mesh	13.6	99.2
-325 Mesh		.8	100.0
TOTAL		100.0	

TABLE VI

BURNS HARBOR C FURNACE
SUMMARY OF OPERATIONS

	HIGH ASH TEST May 28 - June 23, 1997	LOW ASH BASE May 1 - May 27, 1997	PREVIOUS BASE October 1996
Production, NTHM/day	7437	7207	6943
Delays, Min/day	23	55	71
Coke Rate, lbs/NTHM	674	673	661
Nat. Gas Rate, lbs/NTHM	5.0	0	0
Inj. Coal Rate, lbs/NTHM	262	269	264
Total Fuel Rate, lbs/NTHM	940	942	925
Burden %:			
Sinter	34.9	27.0	35.9
Pellets	64.9	72.8	63.8
Misc.	.2	.2	.3
BOF Slag, lbs/NTHM	0	53	5
Blast Conditions:			
Dry Air,SCFM	135,370	135,683	137,000
Blast Pressure, psig	38.3	38.2	38.8
Permeability	1.23	1.25	1.19
Oxygen in Wind, %	28.6	28.5	27.3
Temp, F	2012	2046	2067
Moist., Grs/SCF	20.7	20.4	19.8
Flame Temp, F	3953	4002	3841
Top Temp, F	199	195	226
Top Press, psig	16.6	17.0	16.9
Coke:			
H2O, %	5.0	4.9	5.0
Hot Metal, %:			
Silicon	.49	.51	.50
Standard Dev.	.097	.116	.128
Sulfur	.035	.040	.040
Standard Dev.	.012	.015	.014
Phos.	.073	.069	.072
Mn.	.46	.42	.43
Temp., F	2733	2741	2734
Slag, %:			
SiO2	36.21	36.08	36.54
Al2O3	9.91	9.43	9.63
CaO	39.40	38.86	39.03
MgO	11.32	12.03	11.62
Mn	.45	.42	.46
Sul	1.40	1.45	1.39
B/A	1.10	1.12	1.10
B/S	1.40	1.41	1.39
Volume, lbs/NTHM	461	448	424

TABLE VII

BURNS HARBOR C FURNACE ADJUSTED COKE RATE COMPARISON

Coke Correction Variables:	BASE 5/1/97 - 5/27/97	HIGH ASH TRIAL 5/28/97 - 6/23/97
Natural Gas, lbs/NTHM	0	5.0
Coke Correction, lbs coke		+6.0
Injected Coal, lbs/NTHM	269	262
Coke Correction, lbs coke		-7.0
Burden:		
Pellets, %	72.8	64.9
Coke Correction, lbs coke		+6.3
Sinter,%	27.0	34.9
Coke Correction, lbs coke		+6.3
Wind Volume, SCFM	135,683	135,370
Coke Correction, lbs coke		+.3
Added Moisture, Grs./SCFM Wind	20.4	20.7
Coke Correction, lbs coke		-.9
Iron Silicon Content, %	.51	.49
Coke Correction, lbs coke		+2.0
Iron Sulfur Content, %	.040	.035
Coke Correction, lbs coke		-2.5
Iron Manganese Content, %	.42	.46
Coke Correction, lbs coke		-1.0
Coke Ash, %	7.70	7.50
Coke Correction, lbs coke		+4.0
Blast Temperature, F	2046	2012
Coke Correction, lbs coke		-5.1
TOTAL COKE CORRECTIONS: lbs. coke	BASE	+8.4
Reported Furnace Coke Rate,lbs/NTHM	673	674
Corrected Furnace Coke Rate,lbs/NTHM		682
Coke Rate Difference from the BASE		**+ 9 Pounds of Coke/NTHM**

TABLE VIII

BURNS HARBOR C FURNACE ADJUSTED COKE RATE COMPARISON

Coke Correction Variables:	BASE October 1996	HIGH ASH TRIAL 5/28/97 - 6/23/97
Natural Gas, lbs/NTHM	0	5.0
Coke Correction, lbs coke		+6.0
Injected Coal, lbs/NTHM	264	262
Coke Correction, lbs coke		-2.0
Burden:		
Pellets, %	63.8	64.9
Coke Correction, lbs coke		-.9
Sinter,%	35.9	34.9
Coke Correction, lbs coke		-.8
Wind Volume, SCFM	137,000	135,370
Coke Correction, lbs coke		+1.7
Added Moisture, Grs./SCFM Wind	19.8	20.7
Coke Correction, lbs coke		-2.6
Iron Silicon Content, %	.50	.49
Coke Correction, lbs coke		+1.0
Iron Sulfur Content, %	.040	.035
Coke Correction, lbs coke		-2.5
Iron Manganese Content, %	.43	.46
Coke Correction, lbs coke		-.8
Coke Ash, %	7.70	7.50
Coke Correction, lbs coke		+4.0
Blast Temperature, F	2067	2012
Coke Correction, lbs coke		-8.3
TOTAL COKE CORRECTIONS: lbs. coke	BASE	-5.2
Reported Furnace Coke Rate,lbs/NTHM	661	674
Corrected Furnace Coke Rate,lbs/NTHM		669
Coke Rate Difference from the BASE		**+ 8 Pounds of Coke/NTHM**

TABLE IX

BURNS HARBOR C FURNACE ADJUSTED COKE RATE COMPARISON

Coke Correction Variables:	BASE FEBRUARY 1996	HIGH ASH TRIAL 5/28/97 - 6/23/97
Natural Gas, lbs/NTHM	1.0	4.0
Coke Correction, lbs coke		+4.8
Injected Coal, lbs/NTHM	253	262
Coke Correction, lbs coke		+9.0
Burden:		
Pellets, %	67.7	64.9
Coke Correction, lbs coke		+2.2
Sinter,%	32.1	34.9
Coke Correction, lbs coke		+2.2
Wind Volume, SCFM	145,300	135,370
Coke Correction, lbs coke		+10.4
Added Moisture, Grs./SCFM Wind	14.0	20.7
Coke Correction, lbs coke		-19.4
Iron Silicon Content, %	.43	.49
Coke Correction, lbs coke		-6.0
Iron Sulfur Content, %	.044	.035
Coke Correction, lbs coke		-4.5
Iron Manganese Content, %	.43	.46
Coke Correction, lbs coke		-.8
Coke Ash, %	7.60	7.50
Coke Correction, lbs coke		+2.0
Blast Temperature, F	2075	2012
Coke Correction, lbs coke		-9.4
TOTAL COKE CORRECTIONS: lbs. coke	BASE	-9.5
Reported Furnace Coke Rate, lbs/NTHM		674
Corrected Furnace Coke Rate, lbs/NTHM		664

TABLE X

BURNS HARBOR C FURNACE SULFUR BALANCE
HIGHER ASH COAL TRIAL

SULFUR INPUT:	5/28-6/23/97	SULFUR OUTPUT:	5/28-6/23/97
Material;		Material;	
Furnace Coke, Sulfur Analysis	.71%	*Blast Furnace Slag, Sulfur Analysis*	1.40%
Tons Coke Used	70,461	Total Tons Produced	46,284
Tons Sulfur In	500.3	Tons Sulfur Out	648.0
Injected Coal,Sulfur Analysis	.75%	Blast Furnace Iron,Sulfur Analysis	.035%
Tons Coal Used	26,272	Total Tons Produced	200,799
Tons Sulfur In	197.0	Tons Sulfur Out	70.3
Sinter, Sulfur Analysis	.02%	Flue Dust,Sulfur Analysis	.34%
Tons Sinter Used	111,485	Total Tons Produced	893
Tons Sulfur In	22.3	*Tons Sulfur Out*	3.0
Pellets,Sulfur Analysis	.01%	Filter Cake,Sulfur Analysis	.38%
Tons Pellets Used	206,998	Total Tons Produced	2533
Tons Sulfur In	20.7	Tons Sulfur Out	9.6
Scrap,Sulfur Analysis	.13%	Top Gas, Sulfur Content	2.5grs/100SCF
Tons Scrap Used	2,183	Total Gas Produced, MMCF	100,125
Tons Sulfur In	2.8	Tons Sulfur Out	17.9
TOTAL TONS of SULFUR IN:	**743.1**	TOTAL TONS of SULFUR OUT:	**748.8**
		SULFUR OUT/SULFUR IN	**1.007**

POSTER SESSION ABSTRACTS

A-55® CLEAN FUELS: UTILITY APPLICATIONS

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ABSTRACT

Convinced that water could be added responsibly and economically to the fuel combustion process to reduce harmful emissions, A-55® Clean Fuels' founder, Rudolf W. Gunnerman, began in the 1980s to experiment with mixtures of water and carbon fuels. In 1996, A-55® Clean Fuels, on the basis of many years of successful testing and manufacturing, focused its efforts on the fuel's use in large stationary applications such as utility and industrial boilers. A-55® Clean Fuels are water-phased fuel emulsions that typically contain between 30 to 55% water by volume. Virtually any petroleum product can be used as a base for A-55® Clean Fuels and therefore cheaper, less refined petroleum products such as naphtha and #6 fuel oil can be utilized in applications where these fuels are not typically used because of quality, infrastructure or environmental concerns. A-55® Technology has developed a #6 fuel oil and water emulsion for use primarily in the electric utility and industrial boiler sectors. Applications for this fuel include (i) reburn fuel in coal-fired boilers, (ii) replacement of #6 fuel oil in oil-fired boilers, and (iii) replacement of diesel or natural gas in combustion turbines. In addition, A-55® has successfully demonstrated that emulsified A-55® fuels containing either naphtha or diesel can also be employed in utility and industrial applications.

Several factors contribute to the economic and environmental advantages of this technology. First, A-55® Clean Fuels are provided at a competitive or reduced cost. For example, the Company estimates that A-55® Clean Fuels based on #6 fuel oil are 30% lower in price than natural gas. Second, these fuels also meet or exceed existing or proposed emissions standards (especially NOx requirements) without the need for capital extensive emissions controls. Finally, these fuels can be easily integrated into existing infrastructure. Independent testing has been conducted over the past several months. The results of these tests are presented below since they represent the general performance characteristics of the A-55® Clean Fuels technology.

Pursuant to a test agreement under EPA's Environmental Technology Verification Program, A-55® Clean Fuels were tested in a 2.5 MMBtu/hr firetube boiler at EPA's Research Triangle Park facility. The test program consisted of measuring the emissions of #2 diesel, #2 diesel-based A-55® Clean Fuels, and naphtha-based A-55® Clean Fuels. The A-55® Clean Fuels contained 30% water by volume. No modifications to the boiler were needed to burn the A-55® Clean Fuels. Relative to #2 diesel, NOx emissions were 17-35% lower for the #2-based A-55 Clean Fuels and 35-53% lower for the naptha-based A-55® Clean Fuels. The EPA also conducted preliminary testing that compared NOx emissions from the use of A-55® Clean Fuels with a #6 fuel oil base to that of #6 fuel oil. On average, these tests showed NOx reductions of over 30% with the #6 fuel

oil-based A-55® Clean Fuels. In addition, particulate matter was reduced about 15%. Based on results observed in other systems, the EPA concluded that boilers having higher heat inputs with higher initial NOx concentrations may show a greater reduction of NOx using the A-55® Clean Fuels.

In August 1997, A-55® Clean Fuels were tested in a 45 MW combustion turbine at the Colbert steam plant in Alabama. The tests compared A-55® Clean Fuels using a #2 diesel base to #2 diesel fuel at varying loads. TVA tested #2 diesel and A-5® Clean Fuels using a #2 diesel base with 30% water by volume and 35% water by volume. Tests were conducted at base load (~45 MW), pre-select (~30 MW), and minimum load (~10 MW). Only minor modifications were made to the combustion turbine to allow it to operate with A-55® Clean Fuels. The test results demonstrated that NOx emissions with A-55® Clean Fuels were 53% lower compared to the #2 diesel fuel. Dramatic reductions in NOx were experienced when fuel to the turbine was switched from #2 diesel to A-55® Clean Fuels. In addition, gross power output at base load increased by about 2 MW using the A-55® Clean Fuels. This increased output represents a significant benefit to operators of large-scale combustion turbines.

In February 1998, A-55® Clean Fuels were tested as a reburn fuel in the EER 1 MMBtu/hr Boiler Simulation Facility (BSF). The BSF is designed to provide a subscale simulation of the furnace gas compositions and temperatures found in various utility boilers. Tests included both naptha-based and #6 fuel oil-based A-55® Clean Fuels. Because natural gas is currently a preferred reburn fuel, the effectiveness of A-55® Clean Fuels as reburn fuels was compared to natural gas. Tests were conducted to compare these reburn fuels as a function of initial NOx concentration (300 ppm and 800 ppm), reburn heat input (varied 10% to 24%), residence time (0.50 and 0.75 seconds), and reburn zone stoichiometry (1.02 to 0.84). The effectiveness of reburning is based on the initial concentration of NOx. At initial NOx concentrations of 800 ppm, #6 fuel-oil based A-55® Clean Fuels reduced NOx emissions by over 70%, which was comparable to natural gas at 20% reburn. The #6 fuel oil-based A-55® Clean Fuels slightly outperformed natural gas at 24% reburn. These results suggest that reburning with #6 fuel oil-based A-55® Clean Fuels might be best suited for boilers with high initial NOx concentrations such as cyclone-fired boilers. Follow-on tests of #6 fuel oil-based A-55 ® Clean Fuel are currently being conducted by EER in their 10 MMBtu/hr tower furnace to project its reburning performance to a full scale utility boiler

These various tests demonstrate that A-55® Clean Fuels can achieve significant NOx reductions both when used as a reburn fuel in coal-fired boilers and as a replacement for diesel fuel in combustion turbines. The cost savings for a large utility boiler can be significant. For example, if A-55® Clean Fuels can undercut the cost of other fuels by $.50/MMBtu, the total annual cost savings for a reference boiler would be about $ 1.5 million per year. With the uncertainties of deregulation, major utility companies are seeking cost-effective ways to meet new regulatory requirements. A-55® Clean Fuels provides such an opportunity.

UPDATE OF ABB's PFBC TECHNOLOGY AND PROJECTS

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ABSTRACT

The PFBC combined cycle arrangement provides a high thermal efficiency in the generation of power from coal and other solid fuels. With more advanced steam conditions and especially with higher gas turbine inlet temperatures efficiencies in the range of 50 to 53 % (LHV) can be achieved in the near future.

PFBC also gives excellent environmental control, with sulfur removal of up to 99% and inherently low NOx emission levels, which can be further lowered through the application of NO_X reduction techniques. The ash produced during combustion has unique properties. When mixed with water it slowly hardens to a concrete-like material. This makes it a potentially valuable raw material for construction purposes.

The first generation of ABB's P200 PFBC plants, established during the last ten years in Europe, the United States and Japan, have achieved over 90,000 hours of operation and have given valuable feedback on performance and operation. The first 360 MWe P800 PFBC plant is being built for Kyushu Electric in Japan. And a "second generation" P200 PFBC, with freeboard-firing is under construction in Cottbus in Eastern Germany. It is a combined heat and power plant, which will be connected to the city's district heating grid. The fuel will be local brown coal, and the output from the PFBC unit will be 65 MWe and 90 MW heat. A number of other PFBC projects are under consideration in different countries, including China, South Korea, the United Kingdom, Italy and Israel.

The P200 and P800 PFBC modules have now been uprated to produce 100 and 425 MWe output, respectively. With the use of multiples of the P200 and P800 modules, plants can be built over a wide size range. An extensive cost reduction program has resulted in that PFBC plants now can be offered world-wide by ABB Carbon, together with its licensees and partners, at competitive prices and for a wide range of coals.

The further widening of the fuel spectrum to include low grade "opportunity fuels" such as petroleum coke and oil shale, promises to allow the development of new markets for PFBC. Oil shale, in particular, seems to be a very promising niche fuel for PFBC, leading to over 40 % higher electricity production per ton of oil shale compared to what can be achieved in power plants with atmospheric combustion systems. This, naturally, translates to an economic advantage. The fact that desulfurization also will be near 100 % efficient, due to the large excess of limestone in oil shale, makes the PFBC application of this major energy resource very attractive.

Concerns about a possible global climate change may require a change from fossil to renewable fuels within the next several decades. A first step can then be to replace some of the fossil fuel used in power plants with biomass. This would lead to substantial reductions in the amounts of carbon dioxide emitted per kWh of electricity produced in those plants. Test on the co-firing of coal and biomass in a PFBC plant have been performed in ABB Carbon's Process Test Facility (PTF) with good results. The possibility of applying this type of co-firing in Stockholm Energi's Vaertan PFBC plant is being considered.

The development of ABB's PFBC technology continues. One result of this is the new "zero-stage cyclone" concept, which will further improve the fuel flexibility and performance of PFBC plants. "Zero-stage cyclones" will now be introduced at EPDC's Wakamatsu PFBC plant in Japan, and test operation will begin during 1998.

FOSSIL FUEL POWER INDUSTRY IN RUSSIA

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ABSTRACT

The Russian Power industry at present is stable and in good technical condition. Because of general economic problems and a decrease in electricity consumption, large reserves of generating capacity exist. However, these reserves are somewhat artificial, since a considerable part of the installed power station equipment is approaching the end of its design or useful service life.

The economic and environmental attributes of most of the power stations constructed 30-40 years ago fail to meet today's efficiency or environmental requirements. With this in view, extension of the service life of old power stations by simple replacement of equipment seems unattractive. Repowering or replacement with advanced technologies and equipment with much better performance characteristics is more promising.

Also, the economic difficulties currently being experienced have created a deficit of capital for innovation. Clean Coal Technology demonstration projects, which have matured and reached completion and evolved into industrial application of the most promising or affordable technologies will be discussed from the Russian viewpoint. Of highest priority are NO_x control technologies, such as Selective Non Catalytic Reduction; low-cost SO_2 control technologies employing calcium for long-term, and sodium for short-term operation; and Electrostatic Precipitator upgrading, including flue-gas conditioning to improve fly-ash precipitation.

The national institutional changes, which have been taking place, together with the projected growth in economic activity, are expected to enhance the implementation of power projects incorporating new Clean Coal Technologies.

CTC CONTINUOUS COKEMAKING PROCESS

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ABSTRACT

Coal Technology Corporation (CTC) has merged with Antaeus Energy Corporation to form a new subsidiary entitled, "Antaeus CTC Technical Services, Inc."

During the past 10 years through cost-shared contracts with DOE, CTC has developed, patented, and demonstrated a new process to continuously produce high quality coke in less than four hours without the normal environmental emissions associated with existing by-product coke ovens.

The CTC/CLC® (Char, Liquids, and Coke) Process utilizes a unique twin screw reaction system in a two-stage carbonization system with a low temperature (1000-1200°F) mild gasification stage followed by a high temperature (2000-2200°F) calcining stage in a totally enclosed system with condensing of the coal liquids and the utilization of the off-gases as the reactor heat source and excess heat used for co-generation. The process has been demonstrated in a 10-ton per day pilot plant and is now ready for commercialization.

A commercial plant is now being designed and construction will begin in July 1998. Purchase contracts for foundry coke have been signed with General Motors and off-take agreements for blast furnace coke are being negotiated with Weirton Steel and Elkem Metals Company.

BLAST FURNACE GRANULAR COAL INJECTION COMPARISON OF THE FIRST AND SECOND GENERATION SYSTEMS

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ABSTRACT

The Granular Coal Injection System provided to Bethlehem Steel, Burns Harbor, Indiana, under the third round of the Clean Coal Technology Program has now been operational for more than three years. Details of the operation of this system and the results obtained have been reported by Bethlehem Steel at previous CCT Conferences and others in the Iron and Steel Industry.

The intent of this paper is to build on that base and provide information about subsequent projects involving this technology, and how the systems have continued to evolve.

The Bethlehem Steel installation included all of the equipment to retrieve coal from outdoor stockpiles and prepare it for injection. The injection portion of the project followed a proven model developed by Clyde Pneumatic Conveying (then part of the Simon Group of companies) and British Steel Corporation. The system was operational on six British Steel furnaces. This system included individual injectors (RotoFeeds) for each tuyere on the furnace. In the case of Bethlehem Steel, that equated to twenty six RotorFeeds each for C & D furnaces.

Discussions with potential purchasers subsequent to the Bethlehem Project indicated a market perception of complexity and high cost for the system. As a result, a second generation RotoFeed Injection system was developed. This system does not have quite the same flexibility of the British Steel/Bethlehem systems but retains all of the most important features.

Second generation systems have now been in service for some time at US Steel Fairfield, Birmingham, Alabama, and at Altos Hornos de Mexico S.A., Monclova, Mexico. Those systems are returning results comparable with the more complex first generation systems, both in injection rate and reliability. The paper will compare the systems and results.

In addition, the USS Fairfield installation was able to make use of an existing dried, granular coal stream from a nearby mine site, which provided prepared fuel without the need for a preparation plant. Therefore, at significantly reduce project cost. The fuel supply flow sheet will be reviewed in comparison to a conventional preparation plant.

Finally, future prospects for GCI and other coal related applications of the RotoFeed will be briefly discussed.

ENCOAL MILD COAL GASIFICATION PROJECT–COMMERCIALIZATION OF LFC TECHNOLOGY

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ABSTRACT

ENCOAL Corporation, a wholly owned indirect subsidiary of Zeigler Coal Holding Company, has completed the demonstration phase of a 1,000 Tons per day Liquids From Coal (LFC®) process plant near Gillette, Wyoming. The plant was operated for more than 5 years and delivered 17 unit trains of Process Derived Fuel (PDF®), the low-sulfur, high-Btu solid product to six major utilities. Recent test burns have indicated that the PDF® product can offer the following benefits to utility customers:

- Lower sulfur emissions
- Lower NO_x emissions
- Lower utilized fuel costs
- Long term stable fuel supply

Nearly five million gallons of Coal Derived Liquid (CDL®), a co-product of the LFC® Process, have also been delivered to seven industrial fuel users and one steel mill blast furnace. Additionally, laboratory testing of the CDL® product and process development efforts have indicated that it can be readily upgraded into higher value chemical feedstock and transportation fuels. The CDL® Product offers an economic advantage over traditional sources of these products as well as potential quality advantages.

Commercialization of the LFC® Technology is in progress. Most of the permits have been approved to construct a large scale commercial plant in Wyoming, pending contracts for the products and financing. International commercialization activity is in progress by the LFC® Technology owner, TEK-KOL, a general partnership between SGI International and a Zeigler subsidiary. Reports and brochures documenting the LFC® Process design, plant operating history, product qualities and test burn results will be available at the Poster Session.

PRESSURIZED INTERNALLY CIRCULATING FLUIDIZED-BED BOILER (PICFB) AND INTEGRATED CIRCULATING FLUIDIZED-BED GASIFIER (ICFG)

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ABSTRACT

The technology of the Ebara Internally Circulating Fluidized-bed Boiler (ICFB) can be successfully applied to the pressurized boiler type, the PICFB. It is characterized that requires complicated fluidizing bed material equipment to accommodate changes in operation conditions is not required and the heating surface is not exposed to the combustion gases. As a result, the flue gas temperature is maintained at a constant value, thereby minimizing SO_x, NO_x and CO emissions and assuring stable hot gas filter operation and stable gas turbine efficiency despite changes in operating conditions.

After the completion of the 4MWth pilot plant design and construction, combustion tests were initiated in December 1996. By the end of December 1997, a total of ten test runs, amounting to 1700 hours of operation, were concluded. This total operating time includes a successful 250 hours of continuous operation. The test results have totally confirmed the superior operating performance expected from the ICFB. This underscores that the PICFB is a significant breakthrough in combined cycle power generating system technology, especially the hot gas filter related technology.

Additionally, We have a plan to develop an Integrated Circulating Fluidized-bed Gasifier (ICFG). The ICFG is an advanced gasifier on which the superior performance of PICFB will be applied. The main feature of the ICFG is that the gasifier and the char-combustor are separated from each other and arranged in the same furnace. Therefore, the ICFG is free from trouble caused by handling of hot particles such as bed material or ash or char, which are handled between gasifier and combustor. We will start a hot model test of the pressurized ICFG on April 1999.

COST AND PERFORMANCE OF CLEAN COAL TECHNOLOGIES

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ABSTRACT

The Clean Coal Technology Program, a $6 billion government and industry partnership, is resulting in a wide spectrum of clean energy options for existing and future coal-based applications. This program was initiated by the U.S. Department of Energy in part to mitigate the potential impacts of acid rain. As the program matured and numerous demonstrations were set in place, the focus of the program moved from acid rain control solutions to solutions that address highly efficient utilization of the energy available in coal as well as promotion of value-added products from coal.

It is the diversity of Clean Coal Technology applications and drivers which strengthens the commercialization process and ultimately provides the focal point for the present discussion. Illustrations of the cost-effective deployment of Clean Coal technologies are provided for the prevailing, as well as anticipated, regulatory environment. The existing market structure for coal-based applications and the technological solutions offered from the Clean Coal Technology Program are examined and placed in the context of technical, economic, and environmental performance. The often quoted tenet, "It's not the fuel that's dirty -- it's the manner in which the fuel is utilized", is the challenge that is analyzed in this paper. The Clean Coal Technology impacts on domestic and international regulatory policies are placed in context with the technological and strategic solutions being applied to the energy industry.

DEVELOPMENT OF AN INNOVATIVE FLUIDIZED BED CEMENT KILN SYSTEM

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ABSTRACT

A new fluidized bed cement kiln system has been researched and developed with the objects of burning low grade coals efficiently, reducing NO_x emission significantly, and increasing thermal efficiency by efficiently recovering heat from solids and gas discharged from the process.

This system applying the fluidized technology consists of two-step kilns; i.e., a fluidized bed granulating kiln and a fluidized bed sintering kiln, and two-step coolers; i.e., a fluidized bed quenching cooler and a packed bed cooler.

It is a completely different process from the conventional rotary cement kiln system equipped with a grate cooler, which has been widely used as the most popular process for producing cement clinker. The combination of two-step kilns and two-step coolers gives many advantages to the new system superior to the rotary kiln system.

This new system is expected as a innovative technology which contributes to the global environmental preservation, because its higher energy efficiency leads to the reduction of CO_2 emission and the superior combustion characteristics of fluidized bed enables to utilize low grade coals as well as it reduces NO_x emission drastically.

Furthermore, its superior temperature controllability assures the improvement of cement quality and the diversification of cement in compliance with numerous needs. The basic research and development of the new system started in 1984 and a bench scale test plant with capacity of 2t/d was constructed in 1985. A pilot plant having capacity of 20 tons clinker per day was completed in the middle of 1989, and then a larger scale pilot plant, so called 200 t/d scale-up plant, was completed in the end of 1995, under the subsidy of MITI for both plants. The running tests of the scale-up plant have been continuing since February 1996.

This paper is to report the operational characteristics of this new fluidized bed cement kiln system.

DEVELOPING TECHNOLOGIES - PROVIDING ENERGY SOLUTIONS

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ABSTRACT

KFx Inc. (KFX:ASE) is a responsive energy solutions company whose mission is to develop technologies which enhance energy value with environmental benefits. (Visit KFx on the worldwide web at http://www.kfx.com.) KFx is headquartered in Denver, Colorado.

The centerpiece of KFx's technology is the first commercial K-Fuel plant, located near Gillette, Wyoming, which is now producing environmentally-superior, high-Btu solid fuel. Using clean, low ash but low-Btu sub-bituminous coal from the Powder River Basin as a feedstock, the patented K-Fuel process uses a simple high-pressure vessel operating at high temperature to produce its superior product. This enhanced coal offers many environmental benefits over its already clean feedstock: even lower emissions (when burned) of oxides of sulfur, nitrogen and carbon and reduced trace elements, including mercury.

THE KRW GASIFIER AND HOT GAS DESULFURIZATION SYSTEM

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ABSTRACT

The KRW pressurized fluidized bed coal gasification process operates at moderate temperatures (under 2000°F) and uses air rather than oxygen in the gasification step. The use of air eliminates the need for an oxygen plant.

Coal, limestone, steam and air are fed to the gasifier. Part of the coal is burned to maintain an operating temperature of about 1800°F (982°C), while the remainder devolatizes and reacts with the steam to yield raw fuel gas. The gas contains hydrogen(H2), carbon monoxide(CO), methane(CH4), nitrogen(N2), carbon dioxide(CO2), water vapor(H2O), hydrogen sulfide(H2S), carbonyl sulfide(COS), ammonia(NH3) and entrained particulate matter. Gasifier operating temperatures are high enough to produce a fuel gas free of tars and oils.

The KRW gasification process utilizes advanced hot gas desulfurization (HGDS) technology to control sulfur emissions, and to achieve greater energy efficiency than plants with cold-gas cleanup. The Kellogg HGDS system uses a transport absorber with circulating solid absorbent to remove sulfur from the hot fuel gas leaving the gasifier. Spent sulfur absorbent is continuously withdrawn from the circulating absorbent loop and regenerated in a transport regenerator that is integrated with the absorber. This transport reactor technology is similar to fluid bed catalytic cracking technology used in petroleum refining. It results in considerably lower capital cost and expected operating costs compared to fixed bed desulfurization technology.

The first commercial KRW gasifier, with HGDS, is installed at the Sierra Pacific Power Company's Tracy Power Station near Reno, Nevada.

The KRW technology is owned by The M.W. Kellogg Company, and marketed worldwide through its subsidiary The M.W. Kellogg Technology Company. It is intended that Foster Wheeler USA market KRW gasification technology in IGCC applications in the United States.

CLEAN COAL TECHNOLOGY EVALUATION GUIDE

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ABSTRACT

With competition from Independent Power Producers, Non-Utility Generators, and competing utilities, generation investments is based on market demand, competitive price structure, and technology attributes. This investment involves various decision hurdles in a risky environment where generation will be a low-margin business dominated by low-cost providers. The generation decision-maker is faced with a multitude of technology options, with the most advanced coal-based concepts under development and demonstration in the U.S. Department of Energy's Clean Coal Technology (CCT) Program. Benefits of each are tied to the needs of the generator as dictated by economic and environmental criteria. The technical challenge is integrating the attributes of the selected technology to achieve investors' economic and performance goals.

Clean coal technologies provide business opportunities that generation executives must understand and take advantage of in the new era of competition. Under this new business climate there is a need for providing a decision-maker with information and methods of evaluating competing technologies that are more applicable to today's market conditions. Technology developers, financial investors, and project developers share in the need for these data in order to evaluate investments in power generation upgrades and additions to their utility systems. With the data forthcoming from the CCT program, a partnership of the U.S. Department of Energy and industry, design and operational information is now becoming available to assist in performing the necessary evaluations.

The US Department of Energy is developing a Clean Coal Technology Evaluation Guide to provide consistent communication of CCT data. Contained in this document are the technical, economic, and environmental performance data on CCTs for advanced power generation applications, along with comparative analyses of conventional technologies. Data are presented in a format to assist in the selection of power generation options for application starting in the year 2005. The approach presented in meeting the needs of a decision-maker consists of applying lessons learned in the CCT programs to update technical, cost, and environmental performance data on selected CCTs in a comparative analysis with other state-of-the-art technology options. Through the use of this information, and the methods defined for comparative analysis, a decision-maker can determine appropriate strategies for industry to promote market acceptance of CCTs. The initial slate of CCTs under consideration includes integrated gasified combined cycle and pressurized fluidized-bed combustion, with comparisons to conventional pulverized coal and natural gas combined cycle technologies.

POWER SYSTEMS DEVELOPMENT FACILITY: SYSTEMS OVERVIEW AND OPERATING EXPERIENCE

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ABSTRACT

The Power Systems Development Facility (PSDF) is a Department of Energy (DOE) sponsored engineering scale demonstration of two advanced coal-fired power systems and four hot gas filter systems. The PSDF was designed at sufficient scale so that advanced power systems and components could be tested in an integrated fashion to provide confidence and data for commercial scale-up. This poster session provides an operations summary of the M.W Kellogg transport reactor and a Westinghouse Particulate Control Device (PCD) located at the PSDF. Also included is an overview of the Foster Wheeler Topped Pressurized Fluid Bed Combustor (APFBC) system, which is in the initial stages of start-up.

The transport reactor is an advanced circulating fluidized bed reactor designed to operate as either a combustor or a gasifier. Particulate cleanup is achieved by using one of two PCDs, located downstream of the transport reactor. In the first 18 months of operations, the transport reactor was operated on coal as a combustor for over 2200 hours. The particulate loading and size to the PCD were much larger than desired during the initial testing because of cyclone problems. However, the loading has substantially decreased and design values are now being achieved. The PCD pressure drop has remained low throughout all runs. Operationally, the PCD has worked well, with few mechanical problems. To date ceramic filter elements from Pall, Coors, Schumacher and 3M have been tested up to 1400°F.

The Southern Research Institute's sampling systems on the PCD inlet and outlet have been operated successfully. Isokinetic samples using a batch sampler, a cascade impactor, and a cyclone manifold have provided valuable data to support the operation of the transport reactor and the PCD.

WESTINGHOUSE HOT GAS FILTER TECHNOLOGIES FOR CLEAN COAL APPLICATIONS

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ABSTRACT

Integrated Gasification Combined Cycles (IGCCs) and Pressurized Circulating Fluidized Bed Cycles (PCFBs) are being developed and demonstrated for commercial power generation applications. Hot gas particulate filters (HGPFs) are key components for the successful implementation of advanced IGCC and PCFB power generation cycles. The objective is to develop and qualify through analysis and testing a practical HGPF system that meets the performance and operational requirements of PCFB and IGCC systems. This paper reports on the status of Westinghouse's HGPF commercialization programs including:

- A summary of the integrated HGPF operation at the American Electric Power, Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Project with approximately 6000 hours of HGPF testing completed.

- A summary of approximately 3200 hours of HGPF testing at the Foster Wheeler (FW) 10 MWe PCFB facility located in Karhula, Finland.

- A summary of over 700 hours of HGPF operation at the FW 2 MW_e topping PCFB facility located in Livingston, New Jersey.

- A summary of the design of the HGPFs for the DOE / Southern Company Services, Power System Development Facility (PSDF) located in Wilsonville, Alabama.

- A summary of the design and operating experience to date of the commercial-scale HGPF system for the Sierra Pacific, Piñon Pine IGCC Project. Included will be an overview of the new hot gas filter test facility at Piñon Pine.

- A review of completed testing and a summary of planned testing of Westinghouse HGPFs in Biomass IGCC applications.

- A brief summary of the HGPF systems for the City of Lakeland, McIntosh Unit 4 PCFB Demonstration Project.